XCEL ENERGY INC
Form 10-K
February 27, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ý	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Fiscal Year Ended Dec. 31, 2005
	Or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
800 Nicollet Mall, Minneapolis, Minnesota	**55402**
(Address of Principal Executive Offices)	(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, Chicago, Pacific
Xcel Energy Inc.	Rights to Purchase Common Stock, $2.50 par value per share	New York, Chicago, Pacific
	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. ý 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 ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ý Yes 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. ý

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). ý 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 ý

As of June 30, 2005, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $7,843,601,587 and there were 402,357,588 shares of common stock outstanding.

As of February 21, 2006, there were 403,814,069 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant s Definitive Proxy Statement for its 2006 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

Index

PART I

Item 1 Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Subsidiaries and Affiliate (current and former)	
BMG	Black Mountain Gas Co., a regulated natural gas and propane distribution company
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.
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.
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
Viking	Viking Gas Transmission Co., an interstate natural gas pipeline company
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	
ASLB	Atomic Safety and Licensing Board
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, and the sale of wholesale electricity, in interstate commerce, including the sale of electricity at market-based rates.
IRS	Internal Revenue Service
MEQB	Minnesota Environmental Quality Board. Selects and designates sites for new power plants (capacity of 50MW or more), wind energy conversion plants (capacity of 5MW or more) and routes for electric transmission lines (capacity of 100KV or more) in Minnesota.
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
WPSC	Wyoming Public Service Commission. The state agency that regulates Cheyenne s facilities, rates, accounts, services and issuances of securities.
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 and weatherization program for low-income customers.
DSMCA	Demand-side management cost adjustment. A clause permitting PSCo to recover demand-side management costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. Costs for the low-income energy assistance program are recovered through the DSMCA.
ECA	Electric commodity adjustment. An incentive adjustment mechanism allowing PSCo to compare actual fuel and purchased energy expense in a calendar year to a benchmark formula. The ECA then provides for an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate.
FCA	Fuel clause adjustment. A clause included in NSP-Minnesota s retail electric rate schedules that provides for prospective monthly rate adjustments to reflect the forecasted cost of electric fuel and purchased energy. 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 three-month 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.
ICA	Incentive cost adjustment. A retail adjustment clause that allowed PSCo to equally share between electric customers and shareholders certain fuel and purchased energy costs. This clause expired Dec. 31, 2002. The collection of prudently incurred 2002 ICA costs was amortized over the period June 1, 2002, through March 31, 2005.

IAC	Interim adjustment clause. A retail adjustment clause that allowed PSCo to recover prudently incurred fuel and energy costs not included in electric base rates. The clause expired Dec. 31, 2003.
PCCA	Purchased capacity cost adjustment. Allows PSCo to recover from customers purchased capacity payments to 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. This clause will expire Dec. 31, 2006.
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 12-month period.
QSP	Quality of service plan. Provides for bill credits to Colorado retail customers if PSCo does not achieve certain operational performance targets.
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.
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.

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
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, as amended.
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
EWG	Exempt wholesale generator, as defined under PUHCA
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FIN No. 46	FASB Interpretation No. 46(R) Consolidation of Variable Interest Entities (revised December 2003)-an interpretation of Accounting Research Bulletin 51
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
LDC	Local distribution company. A company or division that obtains the major portion of its revenues from the operations of a retail distribution system for the delivery of electricity or natural gas for ultimate consumption.
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.
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 hydrocarbon and non-hydrocarbon 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.
OMOI	FERC Office of Market Oversight and Investigations
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.
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
SMA	Supply margin assessment
SMD	Standard market design
SO2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor s	Standard & Poor s Ratings Services
TEMT	Transmission and Energy Markets Tariff
TRANSLink	TRANSLink Transmission Co., LLC
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
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 2005, Xcel Energy s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in 10 states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. Along with WGI, an interstate natural gas pipeline company, these companies comprise our continuing regulated utility operations

Xcel Energy s nonregulated subsidiaries in continuing operations include Eloigne and Planergy International, Inc. Planergy International, Inc. closed and began selling a majority of its business operations in 2003 with all operations ceasing in 2004.

Discontinued utility operations include the activity of Viking, which was sold in January 2003; BMG, which was sold in October 2003; and Cheyenne, which was sold in January 2005.

In April 2005, Zachry Group, Inc. acquired all of the outstanding shares of UE, a nonregulated subsidiary. In August 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of Quixx Corp., a former subsidiary of UE that partners in cogeneration projects that was not included in the sale of UE to Zachry. As a result, Xcel Energy is reporting UE and Quixx as components of discontinued operations for all periods presented.

During 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren Innovations, Inc. On Nov. 3, 2005, Xcel Energy completed the sale of Seren s California assets to WaveDivision Holdings, LLC. On Jan. 9, 2006, Xcel Energy completed the sale of Seren s Minnesota assets to Charter Communications.

During 2003, Xcel Energy divested its ownership interest in NRG. On May 14, 2003, NRG filed for bankruptcy to restructure their debt. As a result of the reorganization, Xcel Energy relinquished its ownership interest in NRG. Xcel Energy made payments of $752 million to NRG in 2004. During 2003, the board of directors of Xcel Energy also approved management s plan to exit certain businesses conducted by the nonregulated subsidiaries Xcel Energy International Inc. and e prime inc. NRG, Xcel Energy International, e prime, Seren, UE and Quixx are accounted for as components of discontinued operations.

For more information regarding Xcel Energy s discontinued operations, see Note 2 to the Consolidated Financial Statements.

Historically, Xcel Energy has been a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). As a registered holding company, Xcel Energy, its utility subsidiaries and certain of its non-utility subsidiaries have been subject to extensive regulation by the SEC under PUHCA with respect to numerous matters, including issuances and sales of securities, acquisitions and sales of certain utility properties, payments of dividends out of capital and surplus, and intra-system sales of certain non-power goods and services. In addition, the PUHCA generally limited the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (Energy Act), significantly changing many federal statutes and repealing PUHCA as of February 8, 2006. As part of the repeal of PUHCA, FERC was given more authority over the merger and acquisition of public utilities and more authority over the books and records of public utilities. Despite these increases in FERC s authority, Xcel Energy believes that the repeal of PUHCA will lessen its regulatory burdens and give it more flexibility in the event it were to choose to expand its utility or non-utility businesses.

Besides repealing PUHCA, 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 DOE. FERC and DOE are in various stages of rulemaking in implementing the Energy Act. While the precise impact of these rulemakings cannot be determined at this time, Xcel Energy generally views the Energy Act as legislation that will enhance the utility industry going forward.

Xcel Energy was incorporated under the laws of Minnesota in 1909. Xcel Energy s executive offices are located at 800 Nicollet Mall, Minneapolis, Minn. 55402. 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 and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after 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. Prior to 2000, the regulated utility operations currently conducted by NSP-Minnesota were conducted by the legal entity now operating under the name Xcel Energy. 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 X percent of the total Kwh sales in 2005. 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 1.3 million customers and gas utility service to approximately 0.5 million customers.

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 Financing I, a former special purpose financing trust of NSP-Minnesota, was dissolved in September 2003.

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 242,000 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 Kwh sales in 2005. 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 98,000 customers. See the discussion of the integrated management of the electric production and transmission system of NSP-Wisconsin under NSP-Minnesota, discussed previously.

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 1.2 million natural gas customers in Colorado. The wholesale customers served by PSCo comprised approximately 23 percent of PSCo s total Kwh sales in 2005.

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 whose capital requirements are not significant. PSCo Capital Trust I, a former special purpose financing trust of PSCo, was dissolved in December 2003.

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 395,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas. The wholesale customers served by SPS comprised approximately 38 percent of SPS s total Kwh sales in 2005. A major portion of SPS retail electric operating revenues is derived from operations in Texas. 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. The transaction, subject to regulatory approvals, is expected to be completed in 2006. Southwestern Public Service Capital I, a former special purpose financing trust of SPS, was dissolved in January 2004.

Other Regulated 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.

See financial information regarding the segments of Xcel Energy s business at Note 17 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 will file rate cases with state and federal regulators to earn a return on its investments and recover costs of operations.

Utility Restructuring and Retail Competition The structure of the utility industry has been subject to change. Merger and acquisition activity has been significant as utilities combined to capture economies of scale or establish a strategic niche in preparing for the future. 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, which does not include SPS. Under current law, SPS can file a plan to implement competition, subject to regulatory approval, in Texas on or after Jan. 1, 2007. However, SPS has no plan to implement retail competition in its service area. 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 electric energy sold at wholesale, hydro facility licensing, accounting practices and certain other activities of Xcel Energy s Utility Subsidiaries. State and local agencies have jurisdiction over many of Xcel Energy s activities, including regulation of retail rates and environmental matters.

FERC Rules Implementing 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 to implement the Energy Act repeal of PUHCA by establishing rules for accounting procedures for holding company systems, including cost allocation rules for transactions between companies within a holding company system;

Adopting new regulations to implement changes to the FERC s merger and asset transfer authority under Section 203 of the Federal Power Act;

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; NERC is expected to apply to become designated as the ERO later in 2006;

Adopting rules to implement changes to the Public Regulatory Policy Act of 1978 (PURPA) to allow utility ownership of Qualifying Facilities (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;

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

Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results.

Market-Based Rate Authority The FERC regulates the wholesale sale of electricity. In order to obtain market-based rate authorization from the FERC, utilities are required to submit analyses demonstrating whether they have market power in the relevant markets. Xcel Energy and its utility subsidiaries were previously granted market-based rate authority by the FERC. However, the FERC has subsequently modified its standards making it more difficult for utilities to demonstrate that they do not have market power and thus more difficult to obtain market-based rate authority, particularly in their own service territories.

On Feb. 7, 2005, Xcel Energy on behalf of itself and the utility subsidiaries filed an updated market-power analysis that applied FERC s new standards. This analysis demonstrated that all of the Utility Subsidiaries, with the exception of PSCo, passed the pivotal supplier analysis in their own control areas and all adjacent markets, but that all failed the market share analysis in their own control areas, and in the case of NSP-Minnesota and NSP-Wisconsin, which jointly operate a single control area and accordingly are analyzed as one company, in certain adjacent markets.

In June 2005, the FERC initiated a proceeding to investigate PSCo s and SPS market-based rate authority within their own control areas. The refund effective date that has been set as part of that investigation for such sales is Aug. 12, 2005. Because of the commencement of the MISO Day 2 market, and the FERC s decision consistent with other precedent to analyze NSP-Minnesota and NSP-Wisconsin as part of that larger market, the FERC is not addressing NSP-Minnesota s and NSP-Wisconsin s market power in that investigation. The FERC did require that Xcel Energy make a compliance filing providing information, including information regarding the FERC s affiliate abuse component of its market power analysis and the allegations regarding that component made by an intervenor within 30 days of the date of issuance of its order. The latter compliance filing was submitted on July 5, 2005.

On Aug. 1, 2005, SPS and PSCo submitted a filing to withdraw their market-based rate authority with respect to sales within their control areas. SPS and PSCo proposed to charge existing cost-based rates for sales into the SPS and PSCo control areas. In October 2005, PSCo and SPS filed revised tariff sheets to reflect that limitation on their market-based rate authority. Certain intervenors are still contending that the FERC must hold an investigation regarding SPS market power and the rates that SPS is proposing to charge where it has relinquished market-based rate authority. The matter is pending before the FERC.

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, which began RTO operations in early 2002. SPS is a member of the SPP, which proposes to begin RTO operations on May 1, 2006. SPS has been a member of SPP s regional transmission tariff since 2001. Each RTO separately files for regional transmission tariff rates for approval by FERC. All members within that RTO are then subjected to those rates. SPS has not yet filed for state regulatory authorization in New Mexico to transfer functional control of its transmission system to the SPP RTO. PSCo is currently participating with other utilities in the development of 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 energy market on April 1, 2005. MISO uses security constrained regional economic dispatch and congestion management using locational marginal pricing (LMP) and FTR s. The Day 2 market is intended to provide more efficient generation dispatch over the 15 state MISO region.

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 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 RTO.

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 have been raised regarding the inclusion of certain MISO charges in the FCA. For further discussion, see NSP-Minnesota Pending and Recently Concluded Regulatory Proceedings MPUC. 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.

Performance-Based Regulation In December 2003, the MPUC voted to approve 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. All three plants are located in the Minneapolis - St. Paul metropolitan area. 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.

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%

Pending and Recently Concluded Regulatory Proceedings - FERC

MISO Operations NSP-Minnesota and NSP-Wisconsin are members of the MISO. The MISO is an RTO that provides regional transmission tariff administration services for electric transmission systems, including those of NSP-Minnesota and NSP-Wisconsin. In 2002, NSP-Minnesota and NSP-Wisconsin received all required regulatory approvals to transfer functional control of their high voltage (100 KVand above) transmission systems to the MISO. The MISO membership grants MISO functional control over the operations of these facilities and the facilities of certain neighboring electric utilities.

On April 1, 2005, MISO initiated a regional wholesale energy market using LMP and FTR s Day 2 market pursuant to its TEMT. While it is anticipated the Day 2 market will provide efficiencies through region-wide generation dispatch and increased reliability, as well as long-term benefits through dispatch of power from the most cost-effective sources of generation or transmission, there are costs associated with the Day 2 market. NSP-Minnesota and NSP-Wisconsin have requested recovery of these costs within their respective jurisdictions. For further discussion, see Pending and Recently Concluded Regulatory Proceedings MPUC.

Within MISO, an independent market monitor reviews market bids and prices to identify any unusual activity. The FERC has notified Xcel Energy that it is investigating pricing and market-related issues. Xcel Energy and other market participants continue to work with MISO, the independent market monitor and the FERC to resolve Day 2 market implementation issues such as dispatch methods and settlement calculation details. Xcel Energy also intends to work with these parties to resolve any identified issues.

New business processes, systems and internal controls over financial reporting were planned and implemented by Xcel Energy and MISO during the second quarter of 2005 to conduct business within the MISO Day 2 market. Xcel Energy continues to validate these changes and to review the energy costs and revenues determined by MISO. Xcel Energy and other market participants have disputed certain transactions.

MISO Long Term Transmission Pricing - On Oct. 7, 2005, MISO filed proposed tariff revisions that would allow MISO to regionalize the cost of certain future high voltage transmission lines owned by specific transmission owners but constructed pursuant to the MISO transmission expansion plan. The proposed tariffs reflect stakeholder input to MISO. MISO proposed the tariff revisions to be effective on Feb. 4, 2006. Xcel Energy generally supports the proposed tariff revisions, which should encourage transmission construction by regionalizing a share of the cost of projects providing regional benefits. Comments on or protests to the proposed tariff revisions were filed at FERC in late 2005. In February 2006, the FERC issued an order accepting the tariff revisions, subject to modifications and additional procedures. Xcel Energy cannot predict the ultimate impact of the MISO tariff proposed at this time.

MISO/PJM SECA - On Nov. 18, 2004, FERC issued an order approving portions of a plan providing for continued use of license plate rates for the MISO/PJM region, but rejecting proposed transition payments to compensate transmission owners for reductions in transmission revenues. FERC instead ordered the MISO and PJM to file a Seams Elimination Charge Adjustment (SECA) transition mechanism. The replacement compliance filings were effective Dec. 1, 2004. The FERC order eliminates any transition payments and the SECA filings instead provide for both revenues and payments that net to approximately $86,000 in revenues per month to NSP-Minnesota and

NSP-Wisconsin in 2005.

Various parties sought rehearing of the Nov. 18, 2004 order and/or filed objections to the Nov. 24, 2004 SECA compliance filings. On Feb. 10, 2005, the FERC issued an order accepting the SECA filings effective Dec. 1, 2004, subject to refund, and set the proposals for hearings. The SECA proposals are now in hearings at the FERC. Certain parties have proposed a regional average transition charge, which could shift costs to NSP-Minnesota and NSP-Wisconsin, effective Dec. 1, 2004. Xcel Energy has opposed these regionalized approaches. The final FERC decision is expected to be issued by the end of 2006. Under the FERC orders, the SECA transition charges are set to expire Mar. 31, 2006.

Pending and Recently Concluded Regulatory Proceedings - MPUC

NSP-Minnesota Electric Rate Case In November 2005, NSP-Minnesota requested an electric rate increase of $168 million or 8.05 percent. This increase was based on a requested 11 percent return on common equity, a projected common equity ratio to total capitalization of 51.7 percent and a projected electric rate base of $3.2 billion. On Dec. 15, 2005, the MPUC authorized an interim rate increase of $147 million, subject to refund, which became effective on Jan. 1, 2006. The anticipated procedural schedule is as follows:

March 2nd Intervenor Direct Testimony

March 30th Rebuttal Testimony

April 13th Surrebuttal Testimony

April 20th April 28th Evidentiary Hearings

May 24th Initial Briefs

June 6th Reply Briefs

July 6th Administrative Law Judge Report

September 5th MPUC Order

Renewable Transmission Cost Recovery In 2002, NSP-Minnesota filed for MPUC approval to establish an RCR adjustment mechanism to recover the costs of transmission investments incurred to deliver renewable energy resources. The RCR adjustment mechanism provides for annual filings to set the RCR adjustment rates using updated transmission cost information. The MPUC approved the RCR adjustment mechanism and the two-phase filing mechanism in April 2003. In February 2004, the MPUC conditionally approved the initial Phase 1 facility eligibility determination filing. NSP-Minnesota then filed for approval to recover annual additional transmission costs from May 2004 to December 2004, which were approximately $6 million. The request was approved and the RCR was implemented Dec. 1, 2004. NSP-Minnesota collected approximately $0.2 million in 2004. NSP-Minnesota submitted a filing in February 2005 to determine the eligibility of additional transmission projects and to establish the RCR factors for 2005, seeking recovery of $12.9 million of additional costs in 2005. The MPUC approved revised factors by order dated Jan. 9, 2006, and NSP-Minnesota submitted its compliance filing in late January 2006 for rates to be effective Mar. 1, 2006. In Oct. 2005, NSP-Minnesota revised the recoverable expense to $9.3 million, of which $5.4 million has been recovered. Because of the pending Minnesota rate case, the RCR rates in effect in 2006 will recover only the unrecovered 2005 costs of $3.9 million. All 2006 costs are proposed to be recovered in the Minnesota electric rate case discussed above.

MISO Cost Recovery On Dec. 18, 2004, NSP-Minnesota filed with the MPUC a petition to seek recovery of the Minnesota jurisdictional portion of all net costs associated with the implementation of the MISO Day 2 market through its FCA. The MPUC issued an interim order in April 2005 allowing MISO Day 2 charges to be recovered through the NSP-Minnesota FCA mechanism. In December 2005, the MPUC issued a second interim order approving the recovery of certain MISO charges through the FCA mechanism but requiring that additional charges either be recovered as part of a general rate case or through an annual review process outside the fuel and purchased energy cost recovery mechanism, and requiring refunds of non-FCA costs. The December 2005 MPUC order also suspended the refund obligation until such time as it could reconsider the matter. On Feb. 9, 2006, the MPUC voted to reconsider its December 2005 order. The MPUC on reconsideration determined that parties be directed to determine which charges are appropriately in the FCA and which are more appropriately established in base rates and report back to the MPUC in 60 days; to grant deferred accounting treatment for costs ultimately determined to be included in base rates for a period of 36 months, with recovery of deferred amounts to be reviewed in a general rate case; and that amounts collected to date through the FCA under the April and December 2005 interim orders are not subject to refund. As a result, NSP-Minnesota expects to have the opportunity to recover (or seek to recover in a rate case) all of its MISO Day 2 costs.

In March 2005, the PSCW issued an interim order allowing NSP-Wisconsin deferred accounting treatment of MISO charges. However, the PSCW staff issued an interpretive memorandum in October 2005 asserting that certain MISO costs may not be recovered through the interim fuel cost mechanism and may not be deferrable. NSP-Wisconsin and the other Wisconsin utilities contested staff s interpretation in their November comments to the PSCW. To date, NSP-Wisconsin has deferred approximately $5.7 million of MISO Day 2 costs as a regulatory asset.

Xcel Energy also notified MISO that NSP-Minnesota and NSP-Wisconsin may seek to withdraw from MISO if rate recovery of Day 2 costs is not allowed. Withdrawal would require FERC approval and could require Xcel Energy to pay a withdrawal fee.

In addition, in March 2005, NSP-Minnesota filed petitions similar to the December 2004 Minnesota filing with the NDPSC and the SDPUC proposing changes to allow recovery of the applicable North Dakota and South Dakota jurisdictional portions of the MISO Day 2 market costs. The SDPUC approved the proposed tariff changes effective April 1, 2005, as requested. The NDPSC granted interim recovery through the FCA beginning April 1, 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. To date, the NDPSC has conducted no further proceedings regarding the NSP-Minnesota filing.

Energy Legislation In 2005, the Minnesota Legislature passed and the Governor signed an Omnibus Energy Bill, effective July 1, 2005. Among other things, the new law provides authority for the MPUC to approve rate rider recovery for transmission investments that have been approved through a certificate of need, the biennial transmission plan, or are associated with compliance with the state s renewable energy objective. The statute provides that the rate rider may include recovery of the revenue requirement associated with qualifying projects, including a current return on construction work in progress. NSP-Minnesota is currently preparing a filing to the MPUC for approval of a new tariff to implement this statute.

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 2006, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2003	2004	2005	2006 Forecast
NSP System	8,868	8,665	9,212	9,401

The peak demand for the NSP System typically occurs in the summer. The 2005 uninterrupted system peak demand for the NSP System occurred on June 23, 2005.

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; 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, typically measured in KW or MW, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in Kwh or Mwh, 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 firm and non-firm purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to provide the utility s reserve obligation, 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.

On Dec. 27, 2005, Excelsior Energy Inc. (Excelsior), an independent energy developer, filed a petition with the MPUC seeking to compel NSP-Minnesota to enter into a power purchase agreement related to its proposed integrated gasification, combined-cycle power plant (Mesaba project) that would be located in northern Minnesota. The petition requested the MPUC to determine that the proposed purchase is in the public interest and that the technology proposed for the Mesaba Project, which Excelsior claims is a clean energy technology under Minnesota law, is or is likely to be a least-cost resource pursuant to Minnesota law. NSP-Minnesota has not been provided a full, unredacted copy of the proposed power purchase agreement and has not entered into the power purchase agreement with Excelsior. The petition seeks to compel NSP-Minnesota to purchase at least 13 percent of NSP-Minnesota s electric energy provided to retail customers from the Mesaba Project, which Excelsior claims would require two units of its Mesaba Project each proposed at 603 MW. Excelsior s filing asserts much of its proposal is confidential under the MPUC s rules, including the pricing and other economic terms. NSP-Minnesota is seeking access to the confidential information. The MPUC asked for comments on the process for the filing and comments on the ability to obtain information filed under confidential protection. NSP-Minnesota has asked the MPUC to first resolve issues surrounding the confidential information, then to address legal issues surrounding the proposal and after resolution of those issues, to consider the proposal in light of its legal conclusions.

NSP System Resource Plan On Nov. 1, 2004, NSP-Minnesota filed its 2004 resource plan with the MPUC. The resource plan projects a need for an additional 3,100 MW of electricity resources during the next 15 years, based on an anticipated growth in demand of 1.61 percent annually, or approximately 170 MW per year, during the period. The resource plan:

identifies the need for adding up to 1,125 MW of new base-load electricity generation by 2015;

recommends a new resource acquisition process that includes multiple options for consideration, including generation built by NSP-Minnesota;

recommends increasing energy-saving goals for demand-side energy management programs by nearly 17 percent;

recommends extending the operating licenses for the Prairie Island and Monticello nuclear plants by 20 years (on Jan. 18, 2005, NSP-Minnesota applied for a certificate of need in Minnesota for a dry spent-fuel storage facility at the Monticello plant, and plans to file an application with the federal government to extend the Monticello plant s license and to make similar filings for the Prairie Island plant in 2008);

assumes nearly 1,700 MW of wind power with most developed on NSP-Minnesota s system;

identifies the need for obtaining up to 550 MW of new power resources for peak usage times by 2015 depending on the amount and timing of any base-load resources acquired; and

cites the importance of ensuring that sufficient transmission resources are available to move electricity from generation sources.

On Aug. 1, 2005, the Minnesota Department of Commerce filed comments that Xcel Energy had overestimated its forecast and that there was no need for new resources until 2015. Other parties filed various comments relating to the environmental impacts of the plan, the use of renewable fuels, the need to construct a 600 MW integrated gasification combined-cycle facility in Northern Minnesota, and NSP-Minnesota s monitoring of the Northern Flood Agreement between the Province of Manitoba and various Canadian First Nations.

On Nov. 23, 2005, Xcel Energy filed updated analysis and replies with the MPUC. The updated analysis supported Xcel Energy s original forecast and identified upgrades to certain existing facilities that could provide cost-effective base load energy to Xcel Energy s customers and defer the need for new base load until 2015. The filing also detailed Xcel Energy s examination of new base load options. On the same day, the Minnesota Department of Commerce filed a proposal to select base load resources through a certificate of need process rather than a bidding process. Xcel Energy expects the MPUC to make a final ruling on the Resource Plan and the bidding process in the first half of 2006.

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 MEQB granted a routing permit for the 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 adjustment that allows NSP-Minnesota to recover the revenue requirements associated with certain transmission investments associated with delivery of renewable energy resources through an automatic adjustment mechanism that started in 2004. See the Pending and Recently Concluded Regulatory Proceedings MPUC, Renewable Transmission Cost Recovery section for further discussion.

Purchased Transmission Services NSP-Minnesota and NSP-Wisconsin have contractual arrangements with MISO to deliver power and energy to NSP System native load customers. Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved. Network transmission services include a charge based on the transmission customer s monthly peak demand.

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). Chem Nuclear is the owner and operator of the Barnwell facility, which has been given authorization by South Carolina to accept low-level radioactive waste from states that are not a member of South Carolina s state compact. Envirocare, Inc. operates the Clive facility. NSP-Minnesota has an annual contract with Barnwell, but is also able to utilize the Envirocare 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. On May 29, 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 the plant, for a total of 29 casks. As of Dec. 31, 2005, there were 20 casks loaded and stored at the Prairie Island plant. See Note 15 in the Consolidated Financial Statements for further discussion of the matter.

Visual Inspections Required visual inspections have been performed on the Prairie Island Unit 2 upper and lower reactor vessel heads, and the Unit 1 upper head. Reactor vessel heads for both units were found to be in compliance with all NRC requirements. The reactor vessel upper head for Prairie Island Unit 2 was replaced during the 2005 refueling outage, and Xcel Energy expects to replace the reactor vessel upper head for Prairie Island Unit 1 in early 2006.

Private Fuel Storage (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. The NRC license review process includes formal evidentiary hearings before the ASLB and opportunities for public input. On Sept. 9, 2005, the NRC Commissioners directed the NRC staff to issue the license for PFS, ending the 8-year effort to gain a license for the site. 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 storage and transportation of spent fuel to PFS. Also in December 2005, NSP-Minnesota forwarded a letter to Senator Hatch (UT) indicating 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.

Prairie Island Steam Generator Replacement In the fall of 2004, NSP-Minnesota spent approximately $132 million to successfully replace the Prairie Island Unit 1 steam generators. The Unit 2 steam generators have not yet been replaced, but received the required inspections during the 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 expects to begin the approval process in 2006 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. In March 2005, NSP-Minnesota filed its application with the NRC for an operating license extension for Monticello of up to 20 years. NSP-Minnesota filed its application with the MPUC for Monticello in January 2005 seeking a certificate of need for dry spent fuel storage. Decisions by both the federal and state agencies regarding Monticello re-licensing are expected in early 2007. Prairie Island has initiated the necessary plant assessments and aging analysis to support submittal of similar applications to the NRC and Minnesota, currently planned for submittal in early 2008.

Nuclear Management Co. (NMC) During 1999, NSP-Minnesota, Wisconsin Electric Power Co., Wisconsin Public Service Corporation (WPS) and Alliant Energy Corp. established NMC. The Consumers Power subsidiary of CMS Energy Corp. joined the NMC during 2000.

NMC manages the operations and maintenance at the plants, and is responsible for physical security. NMC s responsibilities also include oversight of on-site dry storage facilities for used nuclear fuel at the Prairie Island nuclear plant. Utility plant owners, including NSP-Minnesota, continue to own the plants, control all energy produced by the plants, and retain responsibility for nuclear liability insurance and decommissioning costs.

In 2005 and 2006, as a result of selling their nuclear plants, WPS and Alliant Energy ended their participation in NMC. In December 2005, Consumer Power announced its intent to sell its nuclear plant, which will leave NSP-Minnesota and Wisconsin Electric Power Co. as the remaining members of the NMC, with a combined total of 3 sites and 5 reactors. NMC is in the process of identifying and marketing its services to other potential nuclear utility candidates to replace the departing members.

For further discussion of nuclear issues, see Notes 14 and 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 during such years.

NSP System	**Coal***		**Nuclear**		**Natural Gas**		**Average Fuel**
Generating Plants	**Cost**	**Percent**	**Cost**	**Percent**	**Cost**	**Percent**	**Cost**
2005	$ 1.04	60%	$ 0.46	36%	$ 8.32	3%	$ 1.11
2004	$ 0.99	61%	$ 0.44	37%	$ 6.48	2%	$ 0.92
2003	$ 0.99	61%	$ 0.43	36%	$ 5.80	2%	$ 0.90

* 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 no less than 30 days of coal inventory at each plant site. Estimated coal requirements at NSP-Minnesota and NSP-Wisconsin s major coal-fired generating plants are approximately 13.3 million tons per year. NSP-Minnesota and NSP-Wisconsin have long-term contracts providing for the delivery of up to 99 percent of 2006 coal requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather, and availability of equipment. See Management s Discussion and Analysis for further discussion of coal delivery disruptions.

NSP-Minnesota and NSP-Wisconsin expect that all of the coal burned in 2006 will have an average sulfur content of less than 0.75 percent. The NSP System has contracts for a maximum of 35.8 million tons of low-sulfur coal for the next 3 years. The contracts are with 1 Montana coal supplier, 3 Wyoming suppliers and 1 Minnesota oil refinery, with expiration dates in 2006 and 2007.

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.

Current nuclear fuel supply contracts cover 100 percent of uranium requirements through 2006 and 91.8 percent of the 2007 requirements with no coverage of requirements for 2008 and beyond. Contracts with additional uranium concentrates 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 requirements cover 100 percent of the requirements for 2006 and 53 percent for 2007 with no current coverage of requirements for 2011 and beyond. A contract with an additional conversion services supplier is nearing completion that is expected to provide additional coverage for 2007 through 2011.

Current enrichment services contracts cover 100 percent of the 2006 requirements. Approximately 30 percent of the 2007 through 2010 requirements are currently covered with no coverage of requirements for 2011 and beyond. These contracts expire at varying times between 2006 and 2010. Contracts with additional enrichment services suppliers are currently in various stages of negotiation that are expected to supply additional coverage from 2007 through 2010.

Fuel fabrication for Monticello is covered through 2010. Fuel fabrication is 100 percent committed for Prairie Island Unit 1 through 2006 and Prairie Island Unit 2 is covered for the 2006 fuel fabrication services under an amendment signed in 2005. NSP-Minnesota and NMC are currently in negotiations with Westinghouse to pursue fuel fabrication for Prairie Island plant needs beyond the current fuel contracts.

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 and enrichment services are currently being negotiated that would provide additional supply requirements through 2016 for uranium and 2010 for enrichment services.

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 which expire in various years from 2006 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, 2005, NSP-Minnesota s commitments related to these contracts were approximately $127 million. The NSP System has current fuel oil inventory adequate to meet anticipated 2006 requirements and also has access to the spot market to buy more oil, 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. Participation in short-term wholesale energy markets provides market intelligence and information that supports the energy management of NSP-Minnesota. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. Engaging in short-term sales and purchase commitments results in an efficient use of our plants and the capturing of additional margins from non-traditional customers. NSP-Minnesota also uses these marketing operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances and changes in fuel prices. 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 to be located within the respective states 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. 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.

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 base rates or 0.5 percent below, the PSCW may hold hearings limited to fuel costs and revise rates upward or downward. Any revised rates would remain in effect until the next rate change. The adjustment approved is calculated on an annual basis, but applied prospectively. NSP-Wisconsin s wholesale electric rate schedules 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.

Pending and Recently Concluded Regulatory Proceedings - FERC

MISO See the discussion of the MISO activity under NSP-Minnesota Pending and Recently Concluded Regulatory Proceedings.

Pending and Recently Concluded Regulatory Proceedings - PSCW

MISO Cost Recovery - On Mar. 29, 2005, NSP-Wisconsin received an order from the PSCW granting its request to defer the costs and benefits attributable to the start-up of the MISO Day 2 energy market. NSP-Wisconsin also received an order granting its request to record energy market transactions on a net basis. The netting of transactions is consistent with the approach envisioned by the FERC in approving the transmission and energy markets tariff and is consistent with generally accepted accounting principles. On Sept. 22, 2005, the PSCW opened an investigation to obtain information from interested persons related to MISO policy development that is beneficial to ratepayers and that protects the public interest. On Oct. 18, 2005, the PSCW solicited comments on the PSCW staff proposal regarding rate and accounting treatment of MISO revenues and costs, as well as a request to escrow MISO Day 2 energy market costs until 2008. On Nov. 17, 2005, NSP-Wisconsin and other Wisconsin utilities filed comments on the PSCW staff proposal and clarified the utilities position on their interpretation of the previously granted deferral order. NSP-Wisconsin will continue to work with the PSCW and other utilities to address the longer-term issue related to MISO policies.

NSP-Wisconsin 2005 Fuel Cost Recovery - On April 22, 2005, NSP-Wisconsin filed an application with the PSCW to increase electric rates by $10 million, or 2.7 percent, annually to provide for recovery of forecasted increased costs of fuel and purchased power over the balance of 2005. The March 2005 actual fuel costs were approximately 13 percent higher than authorized recovery in current base rates, and the forecast for the remainder of 2005 showed costs outside the previously established annual range by 9.6 percent. On May 18, 2005, the PSCW issued an order approving interim rates at the level requested, effective May 19, 2005. This rate increase generated an estimated $6.5 million in additional revenue for NSP-Wisconsin in 2005. Under the provisions of the Wisconsin fuel rules, any difference between interim rates and final rates is subject to refund. On Sept. 28, 2005, the PSCW issued a final order approving an increase of $11.6 million, or 3.1 percent annually. Because the final rates were slightly higher than interim rates authorized in May 2005, no refund was necessary. With an effective date of Oct. 1, 2005, final rates collected approximately $0.4 million in incremental revenue, as compared to interim rates, over the last three months of 2005.

On Oct. 14, 2005, NSP-Wisconsin filed an application with the PSCW to increase the amount of the authorized fuel and purchased power surcharge by $8.9 million or 2.3 percent on an annual basis. This additional request was due to dramatic increases in the cost of natural gas and purchased power since the surcharge amount was set in mid-August. September 2005 actual fuel costs were approximately 38 percent higher than authorized recovery in current rates, and the forecast for the remainder of 2005 showed costs outside the annual range by 7.5 percent. A PSCW order authorizing an increase in the amount of the surcharge on an interim basis, subject to refund, was issued Nov. 10, 2005, and NSP-Wisconsin collected approximately $1.3 million in additional revenue over the remainder of 2005. The surcharge was discontinued with the implementation of new 2006 base rates, which went into effect Jan. 9, 2006. A final hearing in the 2005 fuel surcharge case was held Feb. 10, 2006, to determine whether any refund of interim rates is necessary. NSP-Wisconsin and PSCW staff both filed testimony indicating that actual fuel costs for the period in question exceeded levels assumed in setting interim rates, and no refund is necessary. A final PSCW decision is expected in the first quarter of 2006.

NSP-Wisconsin 2006 General Rate Case In 2005, NSP-Wisconsin, requested an electric revenue increase of $58.3 million and a natural gas revenue increase of $8.1 million, based on a 2006 test year, an 11.9 percent return on equity and a common equity ratio of 56.32 percent. On Jan. 5, 2006, the PSCW approved an electric revenue increase of $43.4 million and a natural gas revenue increase of $3.9 million, based on an 11.0 percent return on equity and a 54-percent common equity ratio target. The new rates were effective Jan. 9, 2006. The order authorized the deferral of an additional $6.5 million in costs related to nuclear decommissioning and manufactured gas plant site clean up for recovery in the next rate case. The order also prohibits NSP-Wisconsin from paying dividends above $42.7 million, if its actual calendar year average common equity ratio is or will fall below 54.03 percent. It also imposes an asymmetrical electric fuel clause bandwidth of positive 2 percent to negative 0.5 percent outside of which NSP-Wisconsin would be permitted to request or be required to change rates.

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 resource costs:

Electric Commodity Adjustment (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 formula rate is revised annually and collected or refunded in the following year, if necessary. The current ECA mechanism will expire Jan. 1, 2007.

Purchased Capacity Cost Adjustment (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. The PCCA will expire on Dec. 31, 2006. Purchased capacity costs both from contracts included within the PCCA and from contracts not included within the PCCA are expected to be eligible for recovery through base rates, when PSCo files its next general rate case.

Steam Cost Adjustment (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 at least annually to coincide with changes in fuel costs.

Air-Quality Improvement Rider (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 to reduce emissions and improve air quality in the Denver metro area.

Demand-Side Management Cost Adjustment (DSMCA) The DSMCA clause currently permits PSCo to recover DSM costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. 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.

PSCo recovers fuel and purchased energy costs from its wholesale 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 annual electric earnings test for 2004 through 2006 with the sharing between customers and shareholders of earnings in excess of a return on equity for electric operations of 10.75 percent;

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 2006; 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 2007.

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.

In 2003, PSCo did not achieve the performance targets for the QSP electric service unavailability measure or the customer complaint measure. Targets were met for the natural gas QSP. There was no sharing of earnings for 2003, as PSCo established new rates in its general rate case.

In 2004, PSCo did not earn a return on equity in excess of 10.75 percent, so no refund liability was recorded. PSCo did not achieve the 2004 performance targets for the electric service unavailability measure, creating a bill credit obligation for 2004 and increasing the maximum bill credit obligation for subsequent years performance. Targets were met for the natural gas QSP.

In 2005, PSCo does not anticipate earning a return on equity in excess of 10.75 percent and did not record a refund liability. QSP results will be filed with the CPUC in April 2006. An estimated customer refund obligation under the electric QSP plan was recorded in 2005 related to the electric service unavailability measure. No refund under the natural gas QSP is anticipated. See further discussion of the QSP below.

Pending and Recently Concluded Regulatory Proceedings - FERC

PSCo and SPS FERC Transmission Rate Case On Sept. 2, 2004, Xcel Energy filed on behalf of PSCo and SPS an application to increase wholesale transmission service and ancillary service rates within the Xcel Energy joint open access transmission tariff (OATT). PSCo and SPS requested an increase in annual transmission service and ancillary services revenues of $6.1 million. As a result of a settlement with certain PSCo wholesale power customers in 2003, their power sales rates would be reduced by $1.4 million. The net increase in annual revenues proposed was $4.7 million, of which $3.0 million is attributable to PSCo. The FERC suspended the filing and delayed the effective date of the proposed increase to June 1, 2005. The interim rates went into effect on June 1, 2005, subject to refund. On Feb. 6, 2006, the parties in the proceeding submitted an uncontested offer of settlement that contains a formula rate for PSCo, a 10.5 percent rate of return on common equity, and the phased inclusion of PSCo s 345 KV tie line costs in wholesale transmission service rates. The settlement results in a $1.6 million rate increase for PSCo effective June 2005. The offer of settlement is pending FERC approval.

California Refund Proceeding A number of proceedings are pending before the FERC relating to the price of sales into the California electricity markets from May 1, 2000 through June 20, 2001. PSCo supplied energy to these markets during this period and has been an active participant in the proceedings. In September 2005, PSCo reached an agreement with respect to these proceedings with a group of California entities including: San Diego Gas & Electric Company, Pacific Gas and Electric Company, Southern California Edison Company, the California Department of Water Resources, the California Electricity Oversight Board, the California Public Utilities Commission and the California Attorney General. In December 2005, the FERC approved the settlement without condition for the period of Jan. 1, 2000 through June 20, 2001. PSCo will pay approximately $5.5 million in cash and assign $1.8 million in accounts receivable from the California Independent System Operator and the California Power Exchange to the settling participants. In 2004, PSCo reserved approximately $7 million related to this proceeding. The settlement, which includes no acknowledgment of wrongdoing by PSCo, avoids further costly litigation and resolves all claims by PSCo against the settling participants and by the settling participants against PSCo. While accounting for approximately 90 percent of purchases in the California markets, the California utilities were not the only purchasers in those markets. However, the settlement makes provision for other purchasers to opt into the settlement. We do not expect a material financial impact as resolution is reached with the non-settling parties.

Pacific Northwest FERC Refund Proceeding In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been an active participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling the FERC has allowed the parties to request additional evidence regarding the use of certain strategies and how they may have impacted the markets in the Pacific Northwest markets. For the referenced period, parties have claimed that the total amount of transactions with PSCo subject to refund are $34 million.

On June 25, 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. On Nov. 10, 2003, in response to requests for rehearing, FERC reaffirmed this ruling to terminate the proceeding without refunds. Certain purchasers have filed appeals of the FERC s orders in this proceeding.

FERC OMOI Compliance Audit On October 28, 2004, the OMOI sent a letter to Xcel Energy stating that OMOI had initiated a routine audit of PSCo compliance with various FERC regulations, including PSCo s OATT, FERC s Order No. 889 standards of conduct rules and PSCo s code of conduct for transactions in power and non-power goods with affiliates with market-based rates. Similar compliance audits of other utilities have resulted in compliance orders and, in certain cases, civil penalties. On November 28, 2005, FERC issued an order approving an audit report that recommended certain operational changes but imposed no civil penalties.

Pending and Recently Concluded Regulatory Proceedings - CPUC

Tie Line Cost Recovery - On Sept. 20, 2001, the CPUC ruled that only 50 percent of the total cost of the high voltage direct current (HVDC) converter constructed by PSCo in Lamar, Colorado would be allowed in rate base. This facility is part of the 345 KV tie line transmission facilities connecting the PSCo and SPS systems. The CPUC decision resulted in a reduction of potential PSCo rate base of approximately $16.7 million. On April 7, 2005, PSCo filed an application with the CPUC proposing a mechanism that would leave half of the HVDC facility as a non-rate-base asset, but that would generate revenue to recover the cost of the non-rate-base asset on a pay-as-you-go basis. The proposal would involve allocating half of any energy or fuel cost savings derived from buying electricity through the tie line or making sales through the tie line. Alternatively, PSCo stated that it would not object to the entire HVDC facility being placed in rate base. A hearing examiner for the CPUC issued a recommended decision on Nov. 16, 2005, that reasoned that 100 percent of the HVDC converter be placed in rate base. The CPUC acted on the recommended decision in February 2006 with generally favorable results.

Quality of Service Plan The PSCo QSP provides for bill credits to Colorado retail customers, if PSCo does not achieve certain operational performance targets. During the second quarter of 2005, PSCo filed its calendar year 2004 operating performance results for electric service unavailability, phone response time, customer complaints, accurate meter reading and natural gas leak repair time measures. PSCo did not achieve the 2004 performance targets for the electric service unavailability measure. The CPUC staff and the OCC disputed the performance results. The parties agreed PSCo did not achieve the 2004 performance targets for the electric service unavailability measure as filed, creating a bill credit obligation for 2004 of $5.6 million. Additionally, the agreement provides that PSCo will invest an additional $11 million in 2006 toward improving reliability, and PSCo will not be required to pay any bill credits that may be owed for 2006 performance results for electric service unavailability. For 2005, PSCo has evaluated its performance under the QSP and has recorded a liability of $13.6 million. Under the electric QSP, the estimated maximum potential bill credit obligation for calendar 2005 performance is approximately $16.8 million, assuming none of the performance targets are met. The maximum potential bill credit obligation for the same period related to permanent natural gas leak repair and natural gas meter reading errors is approximately $1.6 million.

Capacity and Demand

Uninterrupted system peak demand for PSCo s electric utility for each of the last three years and the forecast for 2006, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2003	2004	2005	2006 Forecast
PSCo	6,419	6,483	6,975	6,751

The peak demand for PSCo s system typically occurs in the summer. The 2005 uninterrupted system peak demand for PSCo occurred on July 21, 2005.

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; 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, typically measured in KW or MW, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in Kwh or Mwh, 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 firm and non-firm purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to provide the utility s reserve obligation, 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 36 percent of its total electric system energy needs for 2006 and generate the remainder with PSCo-owned resources. Additional capacity has been secured under contract making additional energy auditable for purchase, if required. PSCo currently has under contract or through owned generation, the resources necessary to meet its anticipated 2006 load obligation.

On April 30, 2004, PSCo filed a least-cost resource plan (LCP) with the CPUC. PSCo s plan showed a need to provide for approximately 3,600 MW of additional generation capacity through 2013 to meet load growth and replace expiring power purchase contracts. The LCP proposed to meet these resource needs through a combination of utility built generation, DSM, and power purchases.

On Dec. 17, 2004, the CPUC approved a settlement agreement between PSCo and intervening parties concerning the LCP. 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.; transfer up to 250 MW of capacity ownership from the 750-MW unit to Intermountain Rural Electric Association and Holy Cross Energy; and install additional emission control equipment on the two existing Comanche station units. PSCo has completed permitting the 750 MW Comanche 3 unit and began construction of the facility in December 2005. In the approved settlement, PSCo also agreed to invest in additional demand-side management and fund environmental programs in Pueblo, Colo.

The approved settlement contains a confidential construction cost cap for the Comanche 3 project (i.e., the new unit and the emission controls on existing units 1 and 2) and a regulatory plan that authorizes PSCo to increase the equity component of its capital structure up to 60 percent in its 2006 rate case 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 IREA that define the respective rights and obligations of PSCo and IREA in the transfer of capacity ownership in the Comanche 3 unit. PSCo continues to discuss the possibility of partnership arrangements with Holy Cross Energy.

PSCo has received the following permits or authorizations for construction and operation of Comanche 3:

Final air quality permits (received July 5, 2005);

A long-term water supply contract with the Pueblo Board of Water Works (received July 19, 2005);

Pueblo City Council approval to annex the Comanche plant into the city (received Sept. 12, 2005) and

Use by Special Review permit for onsite disposal of ash over a 50-year period (received Sept. 27, 2005).

The settlement agreement also called for PSCo to acquire the remaining resource needs through an all-source competitive bidding process. On Feb. 24, 2005, in conjunction with the approved LCP, PSCo released an All-Source solicitation for new supply and demand-side resources. In May 2005, PSCo received proposals for over 11,000 MW of firm capacity, nearly 4,600 MW of nameplate wind capacity, and almost 900 MW of demand-side management programs. On Dec. 28, 2005 PSCo filed a report with the CPUC detailing the bids received, the bid evaluation process, and the winning bids. PSCo selected bids for approximately 30 MW of DSM resources, approximately 1300 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 Portfolio Standards In November 2004, an amendment to the Colorado statutes was passed by referendum requiring implementation of a renewable energy portfolio standard for electric service. The law requires PSCo to generate, or cause to be generated, a certain level of electricity from eligible renewable resources. Generation of electricity from renewable resources, particularly solar energy, may be a higher-cost alternative to traditional fuels, such as coal and natural gas. These incremental costs are expected to be recovered from customers. On March 29, 2005, the CPUC initiated a proceeding and held various hearings to determine the rules and regulations required to implement the renewable portfolio standard. The CPUC determined that compliance with the renewable energy portfolio standard 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 this issue; that Colorado utilities should be required to file implementation plans, thereby rejecting the proposal to use an independent plan administrator; and the methods utilities should use for determining the budget available for renewable resources. The CPUC issued proposed rules on Jan. 27, 2006. Final rules are expected to become effective by the end of the first quarter 2006.

Renewable Energy Standard Adjustment (RESA) On December 1, 2005, PSCo filed with the CPUC to implement a new 1 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. Hearings were held on Feb. 17, 2006. A CPUC decision is pending. PSCo expects the RESA rider will go into effect in early March 2006.

Purchased Transmission Services PSCo 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. Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved, although some agreements may base charges on the amount of metered energy delivered. Network transmission services include a charge for the metered demand at the delivery point at the time of the provider s monthly transmission system peak, usually calculated as a 12-month rolling average.

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 during such years.

	Coal		Natural Gas		Average Fuel
	Cost	Percent	Cost	Percent	Cost
2005	$ 1.01	85%	$ 7.56	15%	$ 2.00
2004	$ 0.89	87%	$ 5.61	13%	$ 1.52
2003	$ 0.92	86%	$ 4.49	14%	$ 1.42

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 no less than 30 days of coal inventory at each plant site. PSCo s generation stations use low-sulfur western coal purchased primarily under long-term contracts with suppliers operating in Colorado and Wyoming. During 2005, PSCo s coal requirements for existing plants were approximately 9.8 million tons. Coal supply inventories at Dec. 31, 2005 were approximately 12 days usage, based on the maximum burn rate for all of PSCo s coal-fired plants. See Management s Discussion and Analysis for further discussion of coal delivery disruptions.

PSCo has contracted for coal suppliers to supply 100 percent of the Cherokee, Cameo, and Valmont stations projected requirements in 2006.

PSCo has long-term coal supply agreements for the Pawnee and Comanche stations projected requirements. Under the long-term agreements the supplier has dedicated specific coal reserves at the contractually defined mines to meet the contract quantity obligations. In addition, PSCo has a coal supply agreement to supply approximately 70 percent of Arapahoe station s projected requirements for 2006. Any remaining Arapahoe station requirements will be procured via spot market purchases.

PSCo operates the jointly owned Hayden generating plant in Colorado. All of Hayden s coal requirements are under contract through the end of 2011. The coal will be trucked approximately 14 miles under a trucking contract effective through 2009 with an option to extend to the end of 2011. In addition to Hayden, PSCo has partial ownership in the Craig generating plant in Colorado. Approximately 70 percent of PSCo s coal requirements for Craig are supplied by two long-term agreements. The remaining coal requirements for Craig are purchased on the spot market under short term contracts. All of 2006 expected requirements for Craig are under contract.

PSCo had a number of coal transportation contracts, which expired over the course of 2005. PSCo has entered into new transportation agreements at rates substantially higher than its 2005 costs.

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, which expire in various years from 2006 through 2025 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, 2005, PSCo s commitments related to these contracts were approximately $205 million.

Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. Participation in short-term wholesale energy markets provides market intelligence and information that supports the energy management of PSCo. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. Engaging in short-term sales and purchase commitments results in an efficient use of our plants and the capturing of additional margins from non-traditional customers. PSCo also uses these marketing operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances and changes in fuel prices. 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 regulates SPS Texas operations as an electric utility and has jurisdiction over its retail rates and services. The municipalities in which SPS operates in Texas have jurisdiction over SPS rates in those communities. The NMPRC has jurisdiction over the issuance of securities. The NMPRC, the Oklahoma Corporation Commission and the Kansas Corporation Commission have jurisdiction with respect to retail rates and services and construction of transmission or generation in their respective states. 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 has filed to withdraw its market-based rate authority with respect to sales in its own control area.

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, as allowed by the PUCT, 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 purchase 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. SPS is scheduled to file for review and reconciliation of its 2004-2005 costs at the end of May 2006.

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 fuel cost adjustment clause accepted for filing by the FERC.

Performance-Based Regulation and Quality of Service Requirements In Texas, SPS is subject to a quality of service plan requiring SPS to comply with electric service reliability, telephone response and abandoned call performance targets. If these targets are not met, SPS is required to make refunds to its customers of up to $950,000 per year. As of Dec. 31, 2005, SPS accrued $800,000 to reflect the expected refund obligation for those measures.

Pending and Recently Concluded Regulatory Proceedings - FERC

PSCo and SPS FERC Transmission Rate Case On Sept. 2, 2004, Xcel Energy filed on behalf of SPS and PSCo an application to increase wholesale transmission service and ancillary service rates within the Xcel Energy joint open access transmission tariff (OATT). PSCo and SPS requested an increase in annual transmission service and ancillary services revenues, which was adjusted to reflect a net increase in annual revenues of $4.7 million, of which $1.7 million is attributable to SPS. The FERC suspended the filing and delayed the effective date of the proposed increase to June 1, 2005. The interim rates went into effect on June 1, 2005, subject to refund. On Feb. 6, 2006, the parties in the proceeding submitted to the settlement judge an uncontested offer of settlement that contains stated rates for SPS, with the opportunity to file revised rates effective Oct. 1, 2006, by which time the SPP is expected to have filed a regional formula transmission rate mechanism similar to MISO. The settlement results in a $1.1 million SPS rate increase effective June 2005. The offer of settlement is pending FERC approval.

SPS Wholesale Rate Complaints In November 2004, several wholesale cooperative customers of SPS filed a $3 million rate complaint at the FERC requesting that the FERC investigate SPS wholesale power base rates and fuel cost adjustment clause calculations. In December 2004, the FERC accepted the complaint filing and ordered SPS base rates subject to refund, effective Jan. 1, 2005. Also in November 2004, SPS filed revisions to its wholesale fuel cost adjustment clause. The FERC set the proposed rate changes into effect on Jan. 1, 2005, subject to refund, and consolidated the proceeding with the wholesale cooperative customers complaint proceeding. The FERC set the consolidated proceeding for hearing and settlement judge procedures, which were terminated when the parties could not reach a settlement. A hearing judge has been appointed by the FERC. Hearings began Feb. 24, 2006 and are expected to last several weeks.

On Sept. 15, 2005, Public Service Company of New Mexico (PNM) filed a separate complaint at the FERC in which it contended that its demand charge under an existing interruptible power supply contract with SPS is excessive and that SPS has overcharged PNM for fuel costs under three separate agreements through erroneous fuel clause calculations. PNM s arguments mirror those that it made as an intervenor in the cooperatives complaint case, and SPS believes that they have little merit. SPS submitted a response to PNM s complaint in October 2005. In November 2005, the FERC accepted PNM s complaint, set it for hearing, suspended hearings and set the matter for settlement judge procedures.

SPS Wholesale Power Base Rate Application In December 2005, SPS filed at the FERC for a $4.1 million annual increase in wholesale power rates for many of its requirements and interruptible capacity wholesale customers. In January 2006, the FERC issued an order conditionally accepting and suspending the proposed rates until July 1, 2006, establishing hearing and settlement judge procedures.

Southwest Power Pool (SPP) Restructuring SPS is a member of the SPP regional reliability council, and SPP acts as transmission tariff administrator for the SPS system. In October 2003, SPP filed for FERC authorization to transform its operation into an RTO. On Oct. 1, 2004, the FERC issued an order granting the SPP status as an RTO. SPS is required to obtain Kansas and NMPRC approval before it can transfer functional control of its electrical transmission system to SPP. When SPP begins RTO operations and SPS obtains all required approvals, SPS will be required to transfer functional control of its electric transmission system to SPP and take all transmission services, including services required to serve retail native loads, under the SPP regional tariff.

SPP Energy Imbalance Service **-** On June 15, 2005, SPP filed proposed tariff provisions to establish an Energy Imbalance Service (EIS) wholesale energy market for the SPP region, using a phased approach toward the development of a fully-functional LMP energy market with appropriate FTR s, to be effective Mar. 1, 2006. On July 15, 2005, Xcel Energy filed a protest addressing the EIS market proposal and urging FERC to reject the proposal and provide guidance to SPP in its effort to design and implement a fully functional Day 2 market for the SPP region to avoid seams between the MISO and SPP regions. On Sept. 19, 2005, FERC issued an order rejecting the SPP EIS proposal and providing guidance and recommendations to SPP; however, the FERC did not require SPP to implement a full Day 2 market similar to MISO. On Jan. 4, 2006, SPP filed a revised EIS market proposal, to be effective May 1, 2006. On Jan. 25, 2006, Xcel Energy protested the revised EIS market proposal, requesting that FERC find SPP s proposal as incomplete and deficient even as a limited market, and reject it on that basis. A final FERC decision is expected later in 2006. SPS has not yet requested NMPRC or PUCT approval regarding accounting and ratemaking treatment of EIS costs.

Pending and Recently Concluded Regulatory Proceedings - PUCT

SPS Texas Retail Fuel Cost Reconciliation Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor. In May 2004, SPS filed with PUCT its periodic request for fuel and purchased power cost recovery for January 2002 through December 2003. SPS requested approval of approximately $580 million of Texas-jurisdictional fuel and purchased power costs for the two-year period. Intervenor testimony contained objections to SPS methodology for assigning average fuel costs to certain wholesale sales, among other things. Recovery of $49 million to $86 million of the requested amount was contested by multiple intervenors.

In 2005, SPS entered into a non-unanimous stipulation with the PUCT staff and several of the intervenors. The stipulation provided reasonable regulatory certainty for SPS on all key issues raised in this proceeding. On Dec. 19, 2005, the PUCT issued an order approving the stipulation. The stipulation reflects a liability of approximately $25 million, which was accrued in 2004. An additional accrual of $4 million was recorded in 2005 to reflect the impact of the order through Dec. 31, 2005. Under the terms of the stipulation, SPS will file a Texas base rate case and its next fuel reconciliation application by the end of May 2006.

Energy Legislation - The 2005 Texas Legislature passed a law, effective June 18, 2005, establishing statutory authority for electric utilities outside of the electric reliability council of Texas in the SPP or the Western Electricity Coordinating Council to have timely recovery of transmission infrastructure investments. After notice and hearing, the PUCT may allow recovery on an annual basis of the reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges under a tariff approved by FERC. The PUCT will initiate a rulemaking for this process that is expected to take place largely in the first quarter of 2006.

Lamb County Electric Cooperative On July 24, 1995, Lamb County Electric Cooperative, Inc. (LCEC) petitioned the PUCT for a cease and desist order against SPS. LCEC alleged that SPS had been unlawfully providing service to oil field customers and their facilities in LCEC s singly-certificated area. The PUCT denied LCEC s petition. See further discussion under Item 3 Legal Proceedings.

Pending and Recently Concluded Regulatory Proceedings - NMPRC

New Mexico Fuel Review - On Jan. 28, 2005, the NMPRC accepted the staff petition for a review of SPS fuel and purchased power cost. The staff requested a formal review of SPS fuel and purchased power cost adjustment clause (FPPCAC) for the period of Oct. 1, 2001 through August 2004. Hearings in the fuel review case have been scheduled for April 2006.

New Mexico Fuel Factor Continuation Filing - The filing to continue the use of SPS FPPCAC was made on Aug. 18, 2005. This filing is required every two years pursuant to the NMPRC rules. The filing proposes that the FPPCAC continue the current monthly factor cost recovery methodology. Certain industrial customers have asked the NMPRC to review SPS assignment of system average fuel cost to certain wholesale capacity sales. Customers have also asked the NMPRC to investigate the treatment of renewable energy certificates and sulfur dioxide allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause. Hearings have been scheduled for April 2006, and a NMPRC decision is expected in late 2006.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2006, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2003	2004	2005	2006 Forecast (a)
SPS	4,661	4,679	4,667	4,603

The peak demand for the SPS system typically occurs in the summer. The 2005 uninterrupted system peak demand for SPS occurred on July 25, 2005.

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, typically measured in KW or MW, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in Kwh or Mwh, 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 firm and non-firm purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to provide the utility s reserve obligation, 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.

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. Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved, although some agreements may base charges on the amount of metered energy delivered. Network transmission services include a charge for the metered demand at the delivery point at the time of the provider s monthly transmission system peak, usually calculated as a 12-month rolling average.

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 during such years.

SPS Generating Plants	Coal Cost	Coal Percent	Natural Gas Cost	Natural Gas Percent	Average Fuel Cost
2005	$ 1.32	68%	$ 7.77	32%	$ 3.38
2004	$ 1.20	69%	$ 5.74	31%	$ 2.60
2003*	$ 0.93	73%	$ 5.24	27%	$ 2.10

* The lower 2003 SPS coal costs reflect a prior period fuel credit adjustment. The normalized cost per MMBtu was approximately $1.14.

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, in turn, 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, 2005, coal supplies at the Harrington and Tolk sites were approximately 36 and 40 days supply, respectively. See Item 7 Management s Discussion & Analysis for discussion of coal delivery disruptions. TUCO has coal supply agreements to supply 100 percent of the projected 2006 requirements for 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.

Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. Participation in short-term wholesale energy markets provides market intelligence and information that supports the energy management of SPS. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. Engaging in short-term sales and purchase commitments results in an efficient use of our plants and the capturing of additional margins from non-traditional customers. On a limited basis, SPS also uses these marketing operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances and changes in fuel prices. See additional discussion under Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Xcel Energy Electric Operating Statistics

	Year Ended Dec. 31, 2005	2004	2003
Electric Sales (Millions of Kwh)			
Residential	23,930	22,828	23,207
Commercial and Industrial	60,049	58,192	57,576
Public Authorities and Other	1,091	1,133	1,165
Total Retail	85,070	82,153	81,948
Sales for Resale	22,194	22,521	21,981
Total Energy Sold	107,264	104,674	103,929
Number of Customers at End of Period			
Residential	2,791,859	2,800,338	2,769,468
Commercial and Industrial	400,035	401,744	398,605
Public Authorities and Other	75,937	79,777	80,875
Total Retail	3,267,831	3,281,859	3,248,948
Wholesale	128	206	211
Total Customers	3,267,959	3,282,065	3,249,159
Electric Revenues (Thousands of Dollars)			
Residential	$ 2,048,100	$ 1,791,606	$ 1,781,179
Commercial and Industrial	3,733,648	3,203,629	3,038,716
Public Authorities and Other	110,895	106,657	107,234
Total Retail	5,892,643	5,101,892	4,927,129
Wholesale	1,193,762	1,011,210	855,389
Other Electric Revenues	157,232	112,143	137,420
Total Electric Revenues	$ 7,243,637	$ 6,225,245	$ 5,919,938
Kwh Sales per Retail Customer	26,033	25,032	25,223
Revenue per Retail Customer	$ 1,803.23	$ 1,554.57	$ 1,516.53
Residential Revenue per Kwh	8.56¢	7.85¢	7.68¢
Commercial and Industrial Revenue per Kwh	6.22¢	5.51¢	5.28¢
Wholesale Revenue per Kwh	5.38¢	4.49¢	3.89¢

NATURAL GAS UTILITY OPERATIONS

Natural Gas Utility Trends

Changes in regulatory policies and market forces have shifted the industry from traditional bundled natural gas sales service to an unbundled transportation and market-based commodity service at the wholesale level and for larger commercial and industrial retail customers. These customers have greater ability to buy natural gas directly from suppliers and arrange their own pipeline and retail LDC transportation service.

The natural gas delivery/transportation business has remained competitive as industrial and large commercial customers have the ability to bypass the local natural gas utility through the construction of interconnections directly with interstate pipelines, thereby avoiding the delivery charges added by the local natural gas utility.

As LDCs, NSP-Minnesota, NSP-Wisconsin and PSCo provide unbundled transportation service to large customers. Transportation service does not have an adverse effect on earnings because the sales and transportation rates have been designed to make them economically indifferent to whether natural gas has been sold and transported or merely transported. However, some transportation customers may have greater opportunities or incentives to physically bypass the LDCs distribution system.

The most significant recent developments in the natural gas operations of the utility subsidiaries was the substantial and continuing increases 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 1995 to 2005, average annual sales to the typical residential customer declined from 104 Dth per year to 87 Dth per year on a weather-normalized basis. Although recent wholesale price increases do not directly affect earnings because of 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 gas supply plans for meeting customers future energy needs.

Purchased Gas and Conservation Cost Recovery Mechanisms NSP-Minnesota s retail natural gas rate schedules 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.

Pending and Recently Concluded Regulatory Proceedings

NSP-Minnesota Natural Gas Rate Case - In September 2004, NSP-Minnesota filed a natural gas rate case for its Minnesota retail customers, seeking a rate increase of $9.9 million, based on a return on equity of 11.5 percent. In August 2005, the MPUC approved an annual rate increase of $5.8 million, based on a return on equity of 10.4 percent. Final rates became effective Dec. 1, 2005.

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 611,950 MMBtu for 2005, which occurred on Jan. 5, 2005.

NSP-Minnesota purchases natural gas from independent suppliers. The natural gas is delivered under natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 521,854 MMBtu/day. In addition, NSP-Minnesota has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 21 percent of winter natural gas requirements and 26 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. NSP-Minnesota s 2004-2005 entitlement levels were approved on July 12, 2005 which allow NSP-Minnesota to recover the demand entitlement costs associated with the increase in transportation, supply, and storage levels in its monthly PGA. In June 2005, NSP-Minnesota also filed to add incremental storage to its portfolio. The increase in storage was approved by the MPUC on Nov. 18, 2005. The 2005-2006 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. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

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

2005	$ 8.90
2004	$ 6.88
2003	$ 5.47

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 2006 through 2027.

NSP-Minnesota has certain natural gas supply and transportation 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, 2005, NSP-Minnesota was committed to approximately $810 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.

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 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 gas rate schedules for Michigan customers include a 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.

Pending and Recently Concluded Regulatory Proceedings - PSCW

See NSP-Wisconsin 2006 General Rate Case discussion under Pending and Recently Concluded Regulatory Proceedings - PSCW in NSP-Wisconsin s Electric Utility Operations section above.

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 154,040 MMBtu for 2005, which occurred on Jan. 17, 2005.

NSP-Wisconsin purchases natural gas from independent suppliers. The natural gas is delivered under natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 122,872 MMBtu/day. In addition, NSP-Wisconsin has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 21 percent of winter natural gas requirements and 29 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 2005-2006 supply plan was approved by the PSCW in October 2005.

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. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

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

2005	$ 8.64
2004	$ 7.00
2003	$ 6.23

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 2006 through 2027.

NSP-Wisconsin has certain natural gas supply and transportation 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, 2005, NSP-Wisconsin was committed to approximately $145 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 a GCA mechanism, which allows PSCo to recover its actual costs of purchased gas. The GCA is revised monthly to allow for changes in gas rates.

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.

Pending and Recently Concluded Regulatory Proceedings

PSCo Natural Gas Rate Case In 2005, PSCo filed for an increase of $34.5 million in natural gas base rates in Colorado, based on a return on equity of 11.0 percent with a common equity ratio of 55.49 percent.

On Jan. 19, 2006, the CPUC approved a settlement agreement between PSCo and other parties to the case. Final rates became effective Feb. 6, 2006. The terms of the settlement include:

- Natural gas revenue increase of $22 million;
- Return on common equity of 10.5 percent;
- Earnings in excess of 10.5 percent return on common equity will be refunded back to customers;
- Common equity ratio of 55.49 percent; and
- Customer charges for the residential and commercial sales classes of $10 and $20 per month, respectively.

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 1,792,770 MMBtu. In addition, firm transportation customers hold 489,014 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,281,784 MMBtu per day. The maximum daily deliveries for PSCo in 2005 for firm and interruptible services were 1,871,486 MMBtu on Dec. 7, 2005.

PSCo purchases natural gas from independent suppliers. The natural gas supplies are delivered to the respective delivery systems through a combination of transportation agreements with interstate pipelines and deliveries by suppliers directly to each company. These agreements provide for firm deliverable pipeline capacity of approximately 1,802,524 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 the companies 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 at Note 14 to the Consolidated Financial Statements.

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. This diversification involves numerous supply sources with varied contract lengths.

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

2005	$ 8.01
2004	$ 6.30
2003	$ 4.94

PSCo has certain natural gas supply and transportation 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, 2005, PSCo was committed to approximately $1.4 billion in such obligations under these contracts, which expire in various years from 2006 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 2005, 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, 2005	2004	2003
Gas Deliveries (Thousands of MMBtu)			
Residential	135,794	134,512	139,107
Commercial and Industrial	83,667	86,053	90,937
Total Retail	219,461	220,565	230,044
Transportation and Other	134,061	116,593	117,343
Total Deliveries	353,522	337,158	347,387
Number of Customers at End of Period			
Residential	1,636,652	1,612,047	1,576,438
Commercial and Industrial	145,067	145,153	147,427
Total Retail	1,781,719	1,757,200	1,723,865
Transportation and Other	3,764	3,544	3,298
Total Customers	1,785,483	1,760,744	1,727,163
Gas Revenues (Thousands of Dollars)			
Residential	$ 1,450,316	$ 1,180,120	$ 1,018,782
Commercial and Industrial	794,230	660,227	592,623
Total Retail	2,244,546	1,840,347	1,611,405
Transportation and Other	62,839	75,167	66,363
Total Gas Revenues	$ 2,307,385	$ 1,915,514	$ 1,677,768
Dth Sales per Retail Customer	123.17	125.52	133.45
Revenue per Retail Customer	$ 1,259.76	$ 1,047.32	$ 934.76
Residential Revenue per MMBtu	$ 10.68	$ 8.77	$ 7.32
Commercial and Industrial Revenue per MMBtu	$ 9.49	$ 7.67	$ 6.52
Transportation and Other Revenue per MMBtu	$ 0.47	$ 0.63	$ 0.57

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 at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, generally, 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 matter discussed below.

Levee Station Manufactured Gas Plant Site A portion of NSP-Minnesota s High Bridge plant coal yard is located on the site of the former Levee Station MGP site. The Levee Station was a coke-oven gas purification, storage and distribution facility. The Levee Station supplied manufactured gas to the city of St. Paul from 1918 to the early 1950s. In the 1950s, the facility was demolished, and the High Bridge coal yard was extended onto the property. In the 1990s, the site was investigated and partially remediated at a cost of approximately $2.9 million. In 2006, NSP-Minnesota plans to commence construction of the High Bridge Combined Cycle Generating Plant, as part of the MERP, on the site of the Levee Station. The construction of the new plant required the removal of buried structures and soil and groundwater remediation. Remediation activities were essentially completed in 2005 at a cost of $3.5 million, which will be accounted for as a capital expenditure of the MERP project.

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, 2005, is presented in the table below. Of the full-time employees listed below, 5,459 or 56 percent, are covered under collective bargaining agreements.

NSP-Minnesota*	2,642
NSP-Wisconsin	538
PSCo	2,595
SPS	1,041

Xcel Energy Services Inc.	2,961
Other subsidiaries	4
Total	9,781

* NSP-Minnesota full-time employees include 347 employees loaned to the NMC. In addition, the NMC has 712 full-time employees of its own.

EXECUTIVE OFFICERS

Richard C. Kelly, 59, 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, 54, President Utilities Group, Xcel Energy, 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, 47, 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.

Gary L. Gibson, 64, President, SPS, December 2000 to present; Chief Executive Officer, SPS, August 2001 to present.

Raymond E. Gogel, 55, Vice President, Xcel Energy Services Inc., April 2002 to present; Chief Information Officer, Xcel Energy Services Inc., April 2002 to February 2006 Vice President Customer and Enterprise Solutions Group, Chief Human Resource Officer and Chief Administrative Officer, November 2005 to present. Previously, 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, 56, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present; Vice President, Corporate Services Group, November 2005 to present.

Gary R. Johnson, 59, Vice President and General Counsel, Xcel Energy Inc., August 2000 to present.

Cynthia L. Lesher, 57, 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, 49, 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, 55, 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, 40, 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, 47, 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, 59, Vice President, Xcel Energy Services, Inc., September 2000 to present; President Energy Supply Group, Xcel Energy, August 2000 to present.

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, which significantly influences our operating environment and our ability to recover our costs from utility customers. 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 profitability of our utility operations is dependent on our ability to recover costs related to providing energy and utility services to our customers. Our public 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 of our costs 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 our costs. Although we believe that the current regulatory environment applicable to our business would permit us to recover the costs of our utility services, it is possible that there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers.

State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. The state utility commissions also may seek to impose restrictions on the ability of our utility subsidiaries to pay dividends to us. If successful, this could materially and adversely affect our ability to meet our financial obligations, including paying dividends on our common stock.

The FERC has jurisdiction over wholesale rates for electric transmission service, electric energy sold at wholesale in interstate commerce, hydro facility licensing and certain other activities of our utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of our other activities, including regulation of retail rates and environmental matters.

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.

We are subject to commodity price risk, credit risk and other risks associated with energy markets.

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products and, accordingly, are subject to commodity price risk, credit risk and other risks associated with these activities.

We are exposed to market and credit risks in our generation, distribution, commodity acquisition, short-term wholesale and commodity trading activities. To minimize the risk of market price fluctuations and product availability, we enter into physical and financial contracts to hedge both price and availability risk associated with purchase and sale commitments, fuel requirements and inventories of coal, natural gas, fuel oil and energy and energy-related products. However, these contracts do not completely eliminate risks, including commodity price changes, market supply shortages, credit risk and interest rate changes. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales commitments or increased interest expense.

Credit and performance 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.

We mark commodity trading derivatives to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. Quoted market prices are utilized 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.

Our subsidiary, PSCo, has received a notice from the Internal Revenue Service (IRS) proposing to disallow certain interest expense deductions that PSCo claimed in 1993 through 1999. 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 corporate-owned life insurance (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 1999.

We believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the law. Accordingly, PSRI has not recorded any provision for income tax or related interest or penalties that may be imposed by the IRS and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years.

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

After Xcel Energy had filed this suit, the IRS sent it two statutory notices of proposed deficiency of tax, penalty, and interest for taxable years 1995 through 1999. Xcel Energy then timely filed two Tax Court petitions challenging those notices. Xcel Energy anticipates that the dispute relating to its claimed interest expense deductions for tax years 1993 and later will be resolved in the refund suit that is pending in the Minnesota federal district court and that the two Tax Court petitions will be held in abeyance pending the outcome of the refund litigation.

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. The case is expected to proceed to trial and the litigation could take another two or more years.

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 that may be imposed by the IRS and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. As discussed above, 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. Although the ultimate resolution of this matter is uncertain, it 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, 2005, would reduce retained earnings by an estimated $361 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2005, is approximately $428 million. Xcel Energy annual earnings for 2006 would be reduced by approximately $44 million, after tax, which represents 10 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 affecting 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 perform environmental remediations and to install pollution control equipment at our facilities. 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 sites where our past activities, or the activities of certain other parties, caused environmental contamination. At December 31, 2005, these sites included:

the site of a former federal uranium enrichment facility;

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, we cannot assure you that existing environmental laws or regulations will not be revised or that new laws or regulations seeking to protect the environment will not be adopted or become applicable to us or that we will not identify in the future conditions that will result in 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 Nuclear Regulatory Commission (NRC) has broad authority under federal law 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. In addition, although we have no reason to anticipate a serious nuclear incident, 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.

Recession, grid disturbances, acts of war or terrorism could negatively impact our business.

The consequences of a prolonged recession and adverse market conditions may include the continued uncertainty of energy prices and the capital and commodity markets. We cannot predict the impact of any economic slowdown or fluctuating energy prices. However, such impact could have a material adverse effect on our financial condition and results of operations.

Also, 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.

The conflict in Iraq and any other military strikes or sustained military campaign may affect our operations in unpredictable ways and may cause changes in the insurance markets, force us to increase security measures and cause disruptions of fuel supplies and markets, particularly with respect to natural gas and purchased energy. The possibility that infrastructure facilities, such as electric generation, transmission and distribution facilities, would be direct targets of, or indirect casualties of, an act of war may affect our operations. War and the possibility of further war may have an adverse impact on the economy in general. 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 war may also affect our ability to raise capital.

Further, like other operators of major industrial facilities, our generation plants, fuel storage facilities and transmission and distribution facilities may be targets of terrorist activities that could result in disruption of 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. To date, we have been able to obtain insurance at satisfactory levels and terms; however, 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.

Reduced coal availability could negatively impact our business.

Xcel Energy s coal generation portfolio is heavily dependent on coal supplies located in the Powder River Basin of Wyoming. Approximately 70 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. In the first half of 2005, we began experiencing disruptions in our coal deliveries from the Powder River Basin, which continued throughout the year and are expected to continue at least through part of 2006. In response to these disruptions Xcel Energy mitigated the impact of reduced coal deliveries, by modifying the dispatch of certain facilities to conserve coal inventories. In addition to the mitigation efforts, Xcel Energy negotiated for the acquisition of additional, higher capacity rail cars and is working to upgrade certain coal handling facilities with completion anticipated in the first half of 2006. Despite, these efforts, coal inventories have declined to below target levels. While we have secured, under contract, approximately 99 percent of our anticipated 2006 coal requirements, we cannot predict with any certainty the likelihood of receiving the required coal. This factor, combined with the currently low inventory levels, has led us to continue coal mitigation. While we are planning to rebuild inventories during 2006, there is no guarantee that we will be able to do so. The ultimate impact of coal availability cannot be fully assessed at this time, but could impact our future results.

Rising energy prices could negatively impact our business.

A variety of market factors have contributed to higher natural gas prices. The direct impact of these higher costs is generally mitigated for Xcel Energy through recovery of such costs from customers through various fuel cost recovery mechanisms. However, higher fuel costs could significantly impact the 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 Xcel Energy s results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases are expected to have an impact on the cash flows of Xcel Energy. Xcel Energy is unable to predict the future natural gas prices or the ultimate impact of such prices on its 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. We expect that unusually mild winters and summers would 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.

Increasing costs associated with our defined benefit retirement plans, health care 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 earnings and funding requirements. Based on our assumptions at Dec. 31, 2005 and assuming continuation of the current federal interest rate relief beyond 2005, in order to maintain required funding levels for our pension plans, we do not expect to make required future contributions. However, it is our practice to make voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations. Therefore, contributions could be required in the future.

In addition to the costs of our retirement plans, 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 with our defined benefit retirement plan, health care plans and other employee benefits 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. To the extent that the state commissions attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends to us, it could adversely affect our ability to pay dividends on our common stock and preferred stock or otherwise meet our financial obligations.

Our utility subsidiaries are subject to regulatory restrictions on accessing capital.

Financings by our utility subsidiaries are subject to prior approval by the applicable state regulatory commission and, possibly, by the FERC. The state utility commissions generally posses broad powers to ensure the needs of the utility customers are being met and there is no assurance they will authorize financings in amounts requested by our utility subsidiaries.

For additional information regarding our liquidity and capital resources, see Item 7 Management s Discussion and Analysis.

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

We cannot assure you 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. Any future downgrade could increase the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any downgrade could lead to higher borrowing costs.

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:

NSP-Minnesota

Station, City and Unit	Fuel	Installed	Summer 2005 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	523
Unit 2	Nuclear	1974	522
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	261
		Total	6,745

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

NSP-Wisconsin

Station, City and Unit	Fuel	Installed	Summer 2005 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*	1940-1948	29
Hydro:			
19 Plants		Various	254
		Total	869

* RDF is refuse-derived fuel, made from municipal solid waste.

PSCo

Station, City and Unit	Fuel	Installed	Summer 2005 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 2005 Net Dependable Capability (MW)**
Steam:			
Harrington-Amarillo, TX 3 Units	Coal	1976-1980	1,066
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	1983	118
CZ-2-Pampa, TX	Purchased Steam	1979	26
Moore County-Amarillo, TX	Natural Gas	1954	48
Gas Turbine:			
Carlsbad-Carlsbad, NM	Natural Gas	1977	13
CZ-1-Pampa, TX	Hot Nitrogen	1965	13
Maddox-Hobbs, NM	Natural Gas	1983	65
Riverview-Electric City, TX	Natural Gas	1973	23
Cunningham-Hobbs, NM 2 Units	Natural Gas	1998	220
Diesel:			
Tucumcari-NM 6 Units		1941-1968	
		Total	4,324

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2005:

Conductor Miles	**NSP-Minnesota**	**NSP-Wisconsin**	**PSCo**	**SPS**
500 KV	2,917			
345 KV	5,648	1,312	832	5,139
230 KV	1,704		10,892	9,408
161 KV	295	1,494		
138 KV			92	
115 KV	6,443	1,529	4,844	10,918
Less than 115 KV	80,534	31,561	70,471	22,519

Electric utility transmission and distribution substations at Dec. 31, 2005:

	NSP-Minnesota	**NSP-Wisconsin**	**PSCo**	**SPS**
Quantity	363	202	208	465

Gas utility mains at Dec. 31, 2005:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	120		2,300	12
Distribution	9,173	2,113	20,168	

Item 3 Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy in addition to the regulatory matters discussed in Item 1. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Legal Contingencies

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 DOE and domestic utilities obligated 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 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. The Court has set the start of the trial on Oct. 23, 2006.

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.

Lamb County Electric Cooperative (SPS) 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 (NSP-Wisconsin) 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 Wisconsin court denied the insurers motion to stay the Wisconsin case pending resolution of the Minnesota action. On Jan. 6, 2005, the Minnesota court issued an injunction prohibiting NSP-Wisconsin from prosecuting the Wisconsin action. On Dec. 27, 2005, the Minnesota Court of Appeals upheld the issuance of the anti-suit injunction. On January 26, 2006, NSP-Wisconsin submitted for filing its petition for review with the Minnesota Supreme Court. On January 13, 2006, the Minnesota trial court extended its stay of the anti-suit injunction until February 28, 2006, or until the Minnesota Supreme Court denies NSP-Wisconsin s petition for review, whichever occurs first. If the petition for review is accepted after February 28, 2006, the parties may seek leave to re-instate the stay. Trial in the Minnesota action is scheduled to commence on November 6, 2006. A status conference in the Wisconsin action is scheduled for February 23, 2006. Trial in the Wisconsin action is scheduled to begin in January 2007.

On January 10, 2006, NSP-Wisconsin, entered into a confidential settlement agreement with St. Paul Mercury Insurance Company, St. Paul Fire and Marine Insurance Company and The Phoenix Insurance Company (St. Paul Companies), and the St. Paul Companies have been dismissed from the Minnesota and Wisconsin actions. The settlement with the St. Paul Companies will not have a material effect on NSP-Wisconsin shareholders.

On Feb. 10, 2006, NSP-Wisconsin filed with the Minnesota court a renewed motion for dismissal under the doctrine of forum non conveniens and a motion for dissolution of the anti-suit injunction. These motions were based upon the changed circumstances resulting from the dismissal of the St. Paul Companies. The St. Paul Companies were the only Minnesota-based insurers and provided what the trial court viewed as a pivotal Minnesota connection supporting its issuance of the anti-suit injunction and denial of NSP-Wisconsin s February 2004 motion to dismiss under the doctrine of forum non conveniens. These motions are currently set for hearing on March 13, 2006.

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 should not have an impact on shareholders, and no accruals have been made.

Hill et al. vs. PSCo et al. - In October 2003, there were two wildfires in Colorado, one in Boulder County and the other in Douglas County. There was no loss of life, but there was property damage associated with these fires. Parties have asserted that trees falling into Xcel Energy distribution lines may have caused one or both fires. On Jan. 14, 2004, an action against PSCo relating to the fire in Boulder County was filed in Boulder County District Court. There are now 46 plaintiffs, including individuals and insurance companies, and three co-defendants, including PSCo. The plaintiffs asserted damages in excess of $35 million. In June 2005, PSCo reached a confidential settlement with all parties, as well as the United States Forest Service and the Denver Public Schools, settling claims in connection with the fire in Boulder County. The financial impact of the settlement was not material to Xcel Energy.

SchlumbergerSema, Inc. vs. Xcel Energy Inc. (NSP-Minnesota) - Under a 1996 data services agreement, as amended, SchlumbergerSema, Inc. (SLB) provided automated meter reading, distribution automation and other data services to NSP-Minnesota. In September 2002, NSP-Minnesota issued written notice that SLB committed events of default under the agreement, including SLB s nonpayment of approximately $7.4 million for distribution automation assets. In November 2002, SLB demanded arbitration and asserted various claims against NSP-Minnesota totaling approximately $24 million for alleged breach of an expansion contract and a meter purchasing contract. In the arbitration, NSP-Minnesota asserted counterclaims against SLB, including those related to SLB s failure to meet performance criteria, improper billing, failure to pay for use of NSP-Minnesota owned property and failure to pay $7.4 million for NSP-Minnesota distribution automation assets, for total claims of approximately $41 million. NSP-Minnesota also sought a declaratory judgment from the arbitrators that would terminate SLB s rights under the data services agreement. In August 2004, the U.S. Bankruptcy Court for the District of Delaware ruled that claims related to use of certain equipment are barred unless NSP-Minnesota can establish a basis for the claims in SLB s conduct subsequent to the time of the assumption of this contract by SLB in May 2000. In June 2005, the U.S.

Bankruptcy Court ruled that NSP-Minnesota is barred from asserting any claim or defense against SLB that is based, in whole or in part, on any pre-May 2000 act or omission, including, but not limited to, any act or omission resulting in design or performance defects, by Cellnet Data Systems Inc., the party with which NSP-Minnesota originally contracted and from which SLB assumed the relevant agreements, which act or omission could have been a basis for NSP-Minnesota to assert a breach of contract against Cellnet Data Systems Inc. On Oct. 31, 2005, the parties submitted this dispute to mediation, and reached a confidential settlement that 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, and Management s Discussion and Analysis under Item 7, 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 2005.

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 Chicago Stock Exchange and the Pacific Stock Exchange. 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 2005 and 2004 and the dividends declared per share during those quarters.

2005	**High**	**Low**	**Dividends**
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

2004	**High**	**Low**	**Dividends**
First Quarter	$ 18.33	$ 16.88	$ 0.1875
Second Quarter	$ 18.04	$ 15.48	$ 0.2075
Third Quarter	$ 17.70	$ 16.32	$ 0.2075
Fourth Quarter	$ 18.78	$ 16.96	$ 0.2075

Book value per share at Dec. 31, 2005, was $13.37. The number of common shareholders of record as of Dec. 31, 2005 was 115,000.

Xcel Energy s Restated Articles of Incorporation provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 2005 and 2004, 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.

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

Item 6 Selected Financial Data

(Millions of Dollars, Except Share and Per-Share Data)	**2005**	**2004**	**2003**	**2002**	**2001**
Operating revenues (a)	$ 9,625	$ 8,216	$ 7,731	$ 6,893	$ 8,527
Operating expenses (a)	$ 8,533	$ 7,140	$ 6,607	$ 5,717	$ 7,272
Income from continuing operations (a)	$ 499	$ 522	$ 523	$ 549	$ 596
Net income (loss)	$ 513	$ 356	$ 622	$ (2,218)	$ 795
Earnings available for common stock	$ 509	$ 352	$ 618	$ (2,222)	$ 791
Average number of common shares outstanding (000 s)	402,330	399,456	398,765	382,051	342,952
Average number of common and potentially dilutive shares outstanding (000 s) (e)	425,671	423,334	418,912	384,646	343,742
Earnings per share from continuing operations - basic (a)	$ 1.23	$ 1.30	$ 1.30	$ 1.43	$ 1.73
Earnings per share-basic	$ 1.26	$ 0.88	$ 1.55	$ (5.82)	$ 2.31
Earnings per share-diluted (e)	$ 1.23	$ 0.87	$ 1.50	$ (5.77)	$ 2.30
Dividends declared per share	$ 0.85	$ 0.81	$ 0.75	$ 1.13	$ 1.50
Total assets (c)	$ 21,648	$ 20,305	$ 20,205	$ 29,436	$ 28,754
Long-term debt (d)	$ 5,898	$ 6,493	$ 6,494	$ 5,294	$ 4,201
Book value per share	$ 13.37	$ 12.99	$ 12.95	$ 11.70	$ 17.91
Return on average common equity	9.6%	6.8%	12.6%	(41.0)%	13.5%
Ratio of earnings to fixed charges (b)	2.2	2.2	2.2	2.5	2.9

(a) Operating revenues and expenses for 2001 through 2004 include reclassifications to conform to the 2005 presentation. These reclassifications relate to reporting electric and natural gas trading revenues and costs on a net basis, reporting fees collected from customers on behalf of governmental agencies net of the related payments made to the agencies and to presenting the results of discontinued operations separately. These reclassifications had no effect on net income.

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

(c) Total assets for 2005, 2004, 2003 and 2002 reflect the classification of accrued future plant removal costs as a component of regulatory liabilities. In 2001, accrued future plant removal costs are reflected as a component of accumulated depreciation. Accrued future removal costs were $896 million, $891 million, $852 million and $800 million in 2005, 2004, 2003 and 2002, respectively.

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

(e) 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.

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

BUSINESS SEGMENTS AND ORGANIZATIONAL OVERVIEW

Xcel Energy Inc. (Xcel Energy), a Minnesota corporation, is a public utility holding company. In 2005, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 10 states. These utility subsidiaries are Northern States Power Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Co. (SPS). These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. Along with WestGas InterState Inc. (WGI), an interstate natural gas pipeline, these companies comprise our continuing regulated utility operations.

Xcel Energy s nonregulated subsidiaries reported in continuing operations include Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax reported credits).

Discontinued utility operations include Viking Gas Transmission Co. (Viking), an interstate natural gas pipeline company that was sold in January 2003; Black Mountain Gas Co. (BMG), a regulated natural gas and propane distribution company that was sold in October 2003; and Cheyenne Light, Fuel and Power Co. (Cheyenne), a regulated electric and natural gas utility that was sold in January 2005.

During 2003, Planergy International, Inc. (Planergy) (energy management solutions) closed, with final dissolution completed in 2004. Several nonregulated subsidiaries are presented as a component of discontinued operations. They include Utility Engineering (UE), an engineering, design and construction management firm; Quixx Corp., a former subsidiary of UE that partners in cogeneration projects; Seren Innovations, Inc. (Seren), a broadband communications services company; NRG Energy, Inc. (NRG), an independent power producer; Xcel Energy International, Inc., an international independent power producer; and e prime inc. (e prime), a natural gas marketing and trading company.

Discontinued operations classifications are the result of sales or plans to sell by management. See Note 2 to the Consolidated Financial Statements for further 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; the higher risk associated with Xcel Energy s nonregulated businesses compared with its regulated businesses; 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 Securities and Exchange Commission (SEC), including Risk Factors in Item 1A of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005 and Exhibit 99.01 to Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005.

MANAGEMENT S STRATEGIC PLAN

Xcel Energy s strategy, which we call Building the Core, is to invest in our core utility businesses and earn the return authorized by our regulatory commissions. We plan to invest approximately $7 billion over the next five years in our core operations to grow our business in response to an increase in customer demand. We anticipate a need for additional energy supply in both Colorado and Minnesota during the next 15 years. Additionally, we continue to focus on enhancing the reliability of our electrical system, which includes making significant investment in our transmission and distribution systems.

Over the past five years, we ve divested 10 businesses or subsidiaries that were not closely linked to our core electric and natural gas businesses, realizing cash proceeds of nearly $440 million. Today, we re a vertically integrated utility and we intend to stay that way.

Our strategy of Building the Core has three phases. The first phase is obtaining legislative and regulatory support for our 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 Metropoliton Emission Reduction Project (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 pieces of legislation will 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 our base level of capital investment, we expect to spend approximately $1 billion on MERP and $1 billion on Comanche 3 through 2010. As a result of these investments, as well as continued investments in our transmission and distribution system, to ensure continued reliability and to meet our customer growth requirements, we expect that our rate base, or the amount on which we earn a return, will grow annually by slightly more than 4 percent on average. Finally, such investments will always be made with a clear focus on optimizing environmental protection, a significant priority for Xcel Energy.

The third phase is earning a fair return on our investments. To ensure that we earn a fair return, 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 us to recover 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.

We also are filing general rate cases to increase revenue recovery in most of the states in which we operate. In 2005, we filed several rate cases as part of our regulatory strategy. These rate cases, and others that we plan to file in 2006, are some of the building blocks of our earnings growth plan. Following is the current status of these initiatives:

We reached constructive decisions in the Colorado natural gas case and Wisconsin electric and natural gas cases, which will increase revenue in 2006 (see Factors Affecting Results of Continuing Operations for further discussion).

We are on track with the Minnesota electric case, where interim rates, subject to refund, went into effect in January 2006. We expect a decision in the third quarter of this year.

Later in the year we plan to file electric cases in Colorado, Texas, New Mexico, and possibly North Dakota and South Dakota. If we are successful, these cases should increase revenue and earnings in 2007.

Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of legitimate expenses and a return on our utility investments. We believe that our commissions will provide us with 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.

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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 from 2005-2009;

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 Notes. 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 generally accepted accounting principles (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., which was classified as held for sale in the third quarter of 2005 based on a decision to divest this investment;

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;

Viking and BMG, which were sold in 2003;

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.

Certain items in the statements of operations have been reclassified from prior-period presentation to conform to the 2005 presentation. See Note 2 to the Consolidated Financial Statements for a further discussion of discontinued operations.

	Contribution to earnings		
(Millions of Dollars)	**2005**	**2004**	**2003**
GAAP income (loss) by segment			
Regulated electric utility segment income continuing operations	$ 440.6	$ 466.3	$ 461.3
Regulated natural gas utility segment income continuing operations	71.2	86.1	94.1
Other utility results (a)	27.6	6.1	6.0
Total utility segment income continuing operations	539.4	558.5	561.4
Holding company costs and other results (a)	(40.3)	(36.2)	(38.6)
Total income continuing operations	499.1	522.3	522.8
Regulated utility income (loss) discontinued operations	0.2	(9.0)	26.8
NRG loss discontinued operations	(1.1)		(251.4)
Other nonregulated income (loss) discontinued operations (b)	14.8	(157.3)	324.2
Total income (loss) discontinued operations	13.9	(166.3)	99.6
Total GAAP net income	$ 513.0	$ 356.0	$ 622.4

	Contribution to earnings per share		
	2005	**2004**	**2003**
GAAP earnings (loss) per share contribution by segment			
Regulated electric utility segment continuing operations	$ 1.04	$ 1.10	$ 1.10
Regulated natural gas utility segment continuing operations	0.17	0.20	0.22
Other utility results (a)	0.06	0.02	0.01
Total utility segment earnings per share continuing operations	1.27	1.32	1.33
Holding company costs and other results (a)	(0.07)	(0.06)	(0.07)
Total earnings per share continuing operations	1.20	1.26	1.26

Regulated utility earnings (loss) discontinued operations		(0.02)	0.06
NRG loss discontinued operations			(0.60)
Other nonregulated earnings (loss) discontinued operations (b)	0.03	(0.37)	0.78
Total earnings (loss) per share discontinued operations	0.03	(0.39)	0.24
Total GAAP earnings per share diluted	$ 1.23	$ 0.87	$ 1.50

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

(b) Includes tax benefit related to NRG. See Note 2 to the Consolidated Financial Statements.

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.

While earnings from continuing operations for 2004 were flat compared with 2003, 2004 results were favorably impacted by electric sales growth, short-term wholesale markets and lower depreciation, offset by the negative impact of unfavorable weather, legal settlement costs and the impact of certain regulatory accruals, compared with the same period in 2003.

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.

The earnings in 2003 from discontinued operations are primarily due to an adjustment to previously estimated tax benefits related to Xcel Energy s write-off of its investment in NRG. Results from discontinued operations are discussed in the Discontinued Operations section later.

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 has used 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 2005 increased earnings by an estimated 3 cents per share;

Weather in 2004 decreased earnings by an estimated 8 cents per share; and

Weather in 2003 was close to normal and had minimal impact on earnings 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 Operations.

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 retail customers in several states, most 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 certain 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, if applicable. Commodity trading revenues are reported net of related costs (i.e., on a margin basis) in the Consolidated Statements of Operations. 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:

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Totals
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%
2003				
Electric utility revenue (excluding commodity trading)	$ 5,724	$ 179	$	$ 5,903
Fuel and purchased power	(2,588)	(118)		(2,706)
Commodity trading revenue			333	333
Commodity trading costs			(316)	(316)
Gross margin before operating expenses	$ 3,136	$ 61	$ 17	$ 3,214
Margin as a percentage of revenue	54.8%	34.1%	5.1%	51.5%

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

(Millions of Dollars)	2005 vs. 2004	2004 vs. 2003
Sales growth (excluding weather impact)	$ 57	$ 73
Estimated impact of weather	91	(74)
Fuel and purchased power cost recovery	706	230
Firm wholesale	67	62
Capacity sales	15	(2)
Quality of service obligations	7	(12)
Conservation and non-fuel riders	16	(5)

Texas fuel reconciliation settlement	21	(25)
Other	69	18
Total base electric utility revenue increase	$ 1,049	$ 265

2005 Comparison with 2004 Base electric 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.

2004 Comparison with 2003 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 1.8 percent; and higher revenues from firm wholesale customers. Partially offsetting the higher revenues was the impact of significantly cooler summer temperatures in 2004, compared with the summer of 2003, as well as estimated customer refunds related to quality-of-service obligations in Colorado and the estimated Texas fuel reconciliation settlement.

Base Electric Utility Margin

(Millions of Dollars)	**2005 vs. 2004**	**2004 vs. 2003**
Estimated impact of weather on sales	$ 75	$ (56)
Sales growth (excluding weather impact)	42	55
Conservation and non-fuel revenue	16	(6)
Texas fuel reconciliation settlement	21	(25)
Quality-of-service obligations	7	(12)
Under-recovery of fuel costs (NSP-Wisconsin)	(15)	(10)
Under-recovery and timing of recovery of fuel costs (other jurisdictions)	(14)	(20)
Firm wholesale	23	27
Pricing and other	8	(16)
Total base electric utility margin increase (decrease)	$ 163	$ (63)

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.

2004 Comparison to 2003 Base electric utility margin decreased due to the impact of weather, higher fuel and purchased energy costs not recovered through direct pass-through recovery mechanisms, and regulatory accruals associated with potential customer refunds related to service-quality obligations in Colorado and fuel-reconciliation proceedings in Texas. These decreases were partially offset by weather-normalized sales growth.

Short-Term Wholesale and Commodity Trading Margin

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.

2004 Comparison to 2003 Short-term wholesale and commodity trading margins increased approximately $33 million in 2004 compared with 2003. The increase reflects a number of market factors, including higher market prices and additional resources available for sale and the pre-existing contract described above.

Natural Gas Utility 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.

(Millions of Dollars)	**2005**	**2004**	**2003**
Natural gas utility revenue	$ 2,307	$ 1,916	$ 1,678
Cost of natural gas purchased and transported	(1,823)	(1,446)	(1,191)
Natural gas utility margin	$ 484	$ 470	$ 487

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

Natural Gas Revenue

(Millions of Dollars)	2005 vs. 2004	2004 vs. 2003
Sales growth (excluding weather impact)	$	$ (3)
Purchased natural gas adjustment clause recovery	397	257
Rate changes Colorado, Minnesota and North Dakota	6	(15)
Estimated impact of weather	(5)	(10)
Transportation and other	(7)	9
Total natural gas revenue increase	$ 391	$ 238

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.

2004 Comparison to 2003 Natural gas revenue increased primarily due to higher natural gas costs in 2004, which are recovered from customers. Retail natural gas weather-normalized sales declined in 2004, largely due to the rising cost of natural gas and its impact on customer usage.

Natural Gas Margin

(Millions of Dollars)	2005 vs. 2004	2004 vs. 2003
Sales growth (excluding weather impact)	$ 1	$
Estimated impact of weather on firm sales	(2)	(5)
Rate changes Colorado, Minnesota and North Dakota	6	(15)
Transportation	6	1
Other	3	2
Total natural gas margin increase (decrease)	$ 14	$ (17)

2005 Comparison to 2004 Natural gas margin increased 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.

2004 Comparison to 2003 Natural gas margin decreased due to a full year of a base rate decrease in Colorado, which was effective July 1, 2003, and the impact of warmer winter temperatures in 2004 compared with 2003.

Nonregulated Operating Margins

The following table details the changes in nonregulated revenue and margin included in continuing operations:

(Millions of Dollars)	2005	2004	2003
Nonregulated and other revenue	$ 74	$ 75	$ 134
Nonregulated cost of goods sold	(25)	(29)	(81)
Nonregulated margin	$ 49	$ 46	$ 53

2004 Comparison to 2003 Nonregulated revenue decreased in 2004, due primarily to the discontinued consolidation of an investment in an independent power-producing entity that was no longer majority owned.

Non-Fuel Operating Expenses and Other Items

Other Utility Operating and Maintenance Expenses Other 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 operating and maintenance expenses for 2004 increased by approximately $21 million, or 1.4 percent, compared with 2003. Of the increase, $12 million was incurred to assist with the storm damage repair in Florida and was offset by increased revenue. The remaining increase of $9 million is primarily due to higher electric service reliability costs, higher information technology costs, higher plant-related costs, higher costs related to a customer billing system conversion and increased costs primarily related to compliance with the Sarbanes-Oxley Act of 2002. The higher costs were partially offset by lower employee benefit and compensation costs and lower nuclear plant outage costs.

(Millions of Dollars)	2005 vs. 2004	2004 vs. 2003
Higher (lower) employee benefit costs	$ 31	$ (12)
Higher (lower) nuclear plant outage costs	26	(13)
Higher uncollectible receivable costs	19	2
Higher donations to energy assistance programs	4	1
Higher mutual aid assistance costs	1	12
Higher electric service reliability costs	9	9
Higher (lower) information technology costs	(6)	8
Higher (lower) plant-related costs	(7)	4
Higher costs related to customer billing system conversion	4	4
Higher costs to comply with Sarbanes-Oxley Act of 2002		4
Other	6	2
Total operating and maintenance expense increase	$ 87	$ 21

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.

Other nonregulated operating and maintenance expenses decreased $9 million, or 17.5 percent, in 2004 compared with 2003. This decrease resulted from the dissolution of Planergy International and the discontinued consolidation of an investment in an independent power producing entity that was no longer majority owned after the divestiture of NRG.

Depreciation and Amortization 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 Minnesota regulators in August 2005.

Depreciation and amortization expense for 2004 decreased by $21 million, or 2.9 percent, compared with 2003. The reduction is largely due to several regulatory decisions. In 2004, as a result of a Minnesota Public Utilities Commission (MPUC) order, NSP-Minnesota modified its decommissioning expense recognition, which served to reduce decommissioning accruals by approximately $18 million in 2004 compared with 2003.

In addition, effective July 1, 2003, the Colorado Public Utilities Commission (CPUC) lengthened the depreciable lives of certain electric utility plant at PSCo as a part of the general Colorado rate case, reducing annual depreciation expense by $20 million. PSCo experienced the full impact of the annual reduction in 2004, resulting in a decrease in depreciation expense of $10 million for 2004 compared with 2003. These decreases were partially offset by plant additions.

Interest and Other Income (Expense) Net 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 $10.5 million in 2004, partially offset by a $2.2 million gain on the sale of water rights in 2005.

Interest and other income, net of nonoperating expenses increased $15 million in 2004 compared with 2003. The increase is due mostly to interest income related to the finalization of prior-period IRS audits of $10.5 million.

Interest and Financing Costs 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.

The 2004 interest charges and financing costs decreased approximately $17 million, or 3.7 percent when compared with 2003. The decrease for the year reflects savings from refinancing higher coupon debt during 2003 and lower credit line fees, partially offset by interest expense related to prior-period IRS audits.

Income Tax Expense 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 $10.0 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.

In 2004, income tax benefits of $37.1 million were recorded, which included $22.3 million related to the successful resolution of various audit issues and other adjustments to current and deferred taxes. The effective income tax rate for continuing operations was 23.7 percent for 2004, compared with 24.6 percent for the same period in 2003. Excluding the tax benefits, the effective rate for 2004 would have been 29.1 percent.

See Note 8 to the Consolidated Financial Statements.

Holding Company and Other Results

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

(Millions of Dollars)	Contribution to Xcel Energy s earnings					
	2005		2004		2003	
Eloigne Company	$	6.2	$	8.5	$	7.7
Financing costs holding company		(52.7)		(44.7)		(44.1)
Holding company and other results		6.2				(2.2)
Total nonregulated/holding company loss continuing operations	$	(40.3)	$	(36.2)	$	(38.6)

	Contribution to Xcel Energy s earnings per share					
	2005		2004		2003	
Eloigne Company	$	0.01	$	0.02	$	0.02
Financing costs and preferred dividends holding company		(0.09)		(0.08)		(0.09)
Holding company and other results		0.01				
Total nonregulated/holding company loss per share continuing operations	$	(0.07)	$	(0.06)	$	(0.07)

Financing Costs and Preferred Dividends Nonregulated 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 2005, 2004 and 2003 included above reflects dilutive securities, as discussed further in Note 9 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 $14 million, or 3 cents per share, in 2005; $15 million, or 4 cents per share, in 2004; and $11 million, or 3 cents per share, in 2003.

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:

	2005	2004	2003
Income (loss) in millions			
Viking Gas Transmission Co.	$	$ 1.3	$ 21.9
Black Mountain Gas			2.4
Cheyenne Light, Fuel and Power Co.	0.2	(10.3)	2.5
Regulated utility segments income (loss)	0.2	(9.0)	26.8
NRG segment loss	(1.1)		(251.4)
NRG-related tax benefits (expense)	17.2	(12.8)	404.4
Xcel Energy International	0.1	7.3	(45.5)
e prime	(0.1)	(1.8)	(17.8)
Seren	1.8	(156.6)	(18.3)
Utility Engineering, Corp. / Quixx Corp.	(4.4)	4.7	3.0
Other	0.2	1.9	(1.6)
Nonregulated/other income (loss)	14.8	(157.3)	324.2
Total income (loss) from discontinued operations	$ 13.9	$ (166.3)	$ 99.6
Income (loss) per share			
Viking Gas Transmission Co.	$	$	$ 0.05
Black Mountain Gas			0.01
Cheyenne Light, Fuel and Power Co.		(0.02)	
Regulated utility segments income per share		(0.02)	0.06
NRG segment loss per share			(0.60)
NRG-related tax benefits (expense)	0.04	(0.03)	0.96
Xcel Energy International		0.02	(0.11)
e prime			(0.04)
Seren		(0.37)	(0.04)
Utility Engineering, Corp. / Quixx Corp.	(0.01)	0.01	0.01
Other			
Nonregulated/other income (loss) per share	0.03	(0.37)	0.78
Total income (loss) per share from discontinued operations	$ 0.03	$ (0.39)	$ 0.24

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.

During 2003, Xcel Energy sold Viking and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded, primarily related to the sale of Viking. Xcel Energy recorded minimal income related to Viking in 2003, due to its sale in January of that year.

NRG Results Discontinued Operations

Xcel Energy s share of NRG results for 2003 is shown as a component of discontinued operations due to NRG s emergence from bankruptcy in December 2003 and Xcel Energy s corresponding divestiture of its ownership interest in NRG. Xcel Energy financial statements do not contain any results of NRG operations in 2005 and 2004.

NRG s results included in Xcel Energy s earnings for 2003 were as follows:

(Millions of Dollars)		Six months ended June 30, 2003
Total NRG loss	$	(621)
Losses not recorded by Xcel Energy under the equity method*		370
Equity in losses of NRG included in Xcel Energy results for 2003	$	(251)

* These represent NRG losses incurred in the first and second quarters of 2003 that were in excess of the amounts recordable by Xcel Energy under the equity method of accounting limitations.

As of the bankruptcy filing date (May 14, 2003), Xcel Energy had recognized $263 million of NRG s impairments and related charges as these charges were recorded by NRG prior to May 14, 2003. Consequently, Xcel Energy recorded its equity in NRG results in excess of its financial commitment to NRG under the settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG s creditors. These excess losses were reversed upon NRG s emergence from bankruptcy in December 2003.

Other Nonregulated Results Discontinued Operations

In April 2005, Zachry Group, Inc. acquired all of the outstanding shares of UE, a nonregulated subsidiary. In August 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of Quixx Corp., a former subsidiary of UE that partners in cogeneration projects that was not included in the sale of UE to Zachry. As a result, Xcel Energy is reporting UE and Quixx as components of discontinued operations for all periods presented.

In September 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren. As a result of the decision, Seren is accounted for as discontinued operations. 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 2003, Xcel Energy s board of directors approved management s plan to exit businesses conducted by e prime and Xcel Energy International. e prime ceased conducting business in 2004. Also during 2004, Xcel Energy completed the sales of the Argentina subsidiaries of Xcel Energy International.

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.

2004 Nonregulated Results Compared with 2003 Results of discontinued nonregulated operations in 2004 include the impact of the sales of the Argentina subsidiaries of Xcel Energy International. The sales were completed in three transactions, with a total sales price of approximately $31 million. In addition to the sales price, Xcel Energy also received approximately $21 million at the closing of one transaction as redemption of its capital investment. The sales resulted in a gain of approximately $8 million, including approximately $7 million of income tax benefits realizable upon the sale of the Xcel Energy International assets.

In addition, 2004 results from discontinued operations include the impact of an after-tax impairment charge for Seren, of $143 million, or 34 cents per share. The impairment charge was recorded based on operating results, market conditions and preliminary feedback from prospective buyers.

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

During 2002, Xcel Energy recognized an initial estimate of the expected tax benefits of $706 million. Based on the results of a 2003 preliminary tax basis study of NRG, Xcel Energy recorded $404 million of additional tax benefits in 2003. In 2004, the NRG basis study was updated and previously recognized tax benefits were reduced by $13 million. In 2005, a $17 million tax benefit was recorded to reflect the final federal income tax resolution of Xcel Energy s divested interest in NRG.

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. In 2005, 2004 and 2003, Xcel Energy used $24 million, $345 million, and $116 million, respectively, of these tax benefits, and expects to use $180 million in 2006. 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. The United States economy continues to grow as measured by projected growth in the gross domestic product. 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 1.4 percent in 2005 compared with 2004, and 1.8 percent in 2004 compared with 2003. Weather-normalized sales growth for firm natural gas utility customers was approximately 0.2 percent in 2005 compared with 2004, and (1.9) percent in 2004 compared with 2003. Projections indicate that weather-normalized sales growth in 2006 compared with 2005 will range between 1.3 percent and 1.7 percent for retail electric utility customers and 0.0 percent to 1.0 percent for firm natural gas utility customers.

Fuel Supply and Costs

Coal Deliverability- Xcel Energy s operating utilities have varying dependence on coal-fired generation. At the utilities, coal-fired generation comprises between 60 percent and 85 percent of the total annual generation. Approximately 70 percent of the annual coal requirements are supplied from the Powder River Basin in Wyoming. Delivery of coal from the Powder River Basin has been disrupted by train derailments and other operational problems purportedly caused by deteriorated rail track beds of approximately 140 miles in length in Wyoming. The BNSF Railway Co. (BNSF) and the Union Pacific Railroad (UPRR) jointly own the rail line. The BNSF operates and maintains the rail line.

The coal delivery issues began in the first half of 2005. Based on discussions with the railroads, Xcel Energy expects that disrupted coal deliveries will continue at least through the first part of 2006. Xcel Energy has taken a number of steps to mitigate the impact of the reduced coal deliveries. These steps include modifying the dispatch of certain generation facilities to conserve coal inventories. This modified dispatch was in place during the second half of 2005 and has continued in 2006 to date. In response to this reduced coal dispatch, Xcel Energy has increased purchases from third parties and has increased the use of natural gas for electric generation. In addition, Xcel Energy negotiated for the acquisition of additional, higher capacity rail cars and is working to upgrade certain coal handling facilities. Delivery of the new cars began in January 2006 and will continue over the course of the year. The upgrades to the coal handling facilities are expected to be completed in the first half of 2006.

Despite these efforts, coal inventories have declined to below target levels. While Xcel Energy has secured, under contract, approximately 99 percent of anticipated 2006 coal requirements, it cannot predict the likelihood of receiving the required coal. While Xcel Energy is planning to rebuild inventories during the year, there is no guarantee that it will be able to do so. The ultimate impact of coal availability cannot be fully assessed at this time, but could impact future financial results.

The cost of purchased power and natural gas for electric generation is higher than for coal-fired electric generation. The use of these sources to replace coal-fired electric generation increased the price of electricity for retail and wholesale customers.

Xcel Energy s utility subsidiaries have discussed this situation with their respective state regulatory commissions.

In Colorado, PSCo is subject to a retail electric adjustment clause that recovers fuel, purchased energy and resource costs. The Electric Commodity Adjustment (ECA) is an incentive adjustment mechanism that compares actual fuel and purchased energy expenses in a calendar year to a benchmark formula. The benchmark formula increases with natural gas prices, but not necessarily with increased volumes of natural gas usage due to coal supply disruption. Therefore, any disruption in coal supply could adversely affect fuel cost recovery. For 2005, PSCo recorded an incentive accrual of $8.5 million. The ECA provides for an $11.25 million cap on any cost sharing over or under the allowed ECA formula rate. Any cost in excess of the $11.25 million cap is completely recovered from customers, while any savings in excess of the $11.25 million cap is completely refunded to customers. Subject to the terms of the ECA, PSCo anticipates it would recover any increased fuel and purchased energy costs greater than the cap from its customers.

Natural gas prices in 2005 were higher than projected when the ECA tariff rates were set in January 2005. On Oct. 5, 2005, PSCo filed an application to adjust the ECA rate for November and December 2005 to reduce the ECA deferred balance and to update its projection of natural gas prices. This application was granted, which resulted in an increase to 2005 electric revenue of approximately $70 million, including unbilled revenues. As of Dec. 31, 2005, PSCo was carrying a deferred ECA balance, including unbilled revenue, of approximately $15 million.

In Texas, fuel and purchased energy costs are recovered through a fixed fuel and purchased energy recovery factor, which is part of SPS retail electric rates. If SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the Public Utility Commission of Texas (PUCT). The regulations require surcharging of under-recovered amounts, including interest, when they exceed 4 percent of SPS annual fuel and purchased energy costs, as allowed by the PUCT, if the condition is expected to continue. On Dec. 21, 2005 SPS reached a settlement with various parties that set the fuel surcharge request at $76.9 million, to be recovered over a 15-month period. The PUCT approved this settlement on Feb. 9, 2006, and the surcharge went into effect Feb. 13, 2006.

In New Mexico, increases and decreases in fuel and purchased energy costs, including deferred amounts, are recovered through a monthly fuel and purchased power clause with a two-month lag. Wholesale customers, under the Federal Energy Regulatory Commission (FERC) jurisdiction also pay a monthly fuel cost adjustment calculated on actual fuel and purchased power costs in accordance with the FERC s fuel clause regulations.

While SPS believes that it should be allowed to recover these higher costs, the ultimate success of recovery could significantly impact the future of SPS and possibly Xcel Energy.

NSP-Minnesota s retail electric rate schedules in the Minnesota, North Dakota and South Dakota jurisdictions include a fuel clause adjustment (FCA) 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 items used to generate electricity at its plants and energy purchased from other suppliers. 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 anticipates it will recover increased costs resulting from its mitigation plan through the FCA.

In Wisconsin, NSP-Wisconsin does not have an automatic electric fuel clause adjustment for Wisconsin retail customers. NSP-Wisconsin may seek deferred accounting treatment and future rate recovery of increased costs due to an emergency event, if that event causes fuel and purchased power costs to exceed the amount included in rates on an annual basis by more than 2 percent. Coal deliverability has not resulted in an emergency event to date.

Natural Gas Costs - A variety of market factors have contributed to significantly higher natural gas prices. The direct impact of these higher costs is generally mitigated for Xcel Energy through recovery of such costs from customers through various fuel cost-recovery mechanisms. However, higher fuel costs could significantly impact the 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 Xcel Energy s results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases are expected to have an impact on the cash flows of Xcel Energy. Xcel Energy is unable to predict the future natural gas prices or the ultimate impact of such prices on its results of operations or cash flows.

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 10 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, and are expected to increase further over the next several years, due to lower-than-expected investment returns experienced in prior years and decreases in interest rates used to discount benefit obligations. While investment returns exceeded the assumed level of 8.75 percent in 2005, 9.0 percent in 2004 and 9.25 percent in 2003, investment returns in 2002 and 2001 were below the assumed level of 9.5 percent, and discount rates have declined from the 7.25-percent to 8-percent levels used in the 1999 through 2002 cost determinations, to 6.0 percent used in 2005. Xcel Energy continually reviews its pension assumptions and, in 2006, expects to maintain the investment return assumption at 8.75 percent and to lower the discount rate assumption to 5.75 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 increase from a credit, or negative expense, of $2.4 million in 2005 to an expense of $15.3 million in 2006 and $18.7 million in 2007. Pension costs were a credit in 2005 due to the recognized investment asset returns exceeding the other pension cost components, such as benefits earned for current service and interest costs for the effects of the passage of time on discounted obligations.

Xcel Energy bases its discount rate assumption on benchmark interest rates from Moody s Investors Service (Moody s), and has consistently benchmarked the interest rate used to derive the discount rate to the movements in the long-term corporate bond indices for bonds rated Aaa through Baa by Moody s, which have a period to maturity comparable to our projected benefit obligations. At Dec. 31, 2005, the annualized Moody s Baa index rate was 6.21 percent, and the Aaa index rate was 5.26 percent. Accordingly, Xcel Energy lowered the discount rate to 5.75 percent as of Dec. 31, 2005. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2006 pension cost determinations. At Dec. 31, 2004, the annualized Moody s Baa index rate was 6.10 percent and the Aaa index rate was 5.43 percent. The corresponding pension discount rate was 6.00 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 2006 recognized pension costs by $17.0 million;

A 100 basis point lower rate of return, 7.75 percent, would increase 2006 recognized pension costs by $17.0 million;

A 100 basis point higher discount rate, 6.75 percent, would decrease 2006 recognized pension costs by $5.4 million; and

A 100 basis point lower discount rate, 4.75 percent, would increase 2006 recognized pension costs by $7.1 million.

Alternative Employee Retirement Income Security Act of 1974 (ERISA) funding assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be affected by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in recent years for Xcel Energy s pension plans, and do not require funding in 2006. Assuming that future asset return levels equal the actuarial assumption of 8.75 percent for the years 2006 and 2007, Xcel Energy projects, under current funding regulations, that no cash funding would be required for 2006 or 2007. Actual performance can affect these funding requirements significantly. Current funding regulations are under legislative review in 2006 and, if not retained in their current form, could change these funding requirements materially.

Regulation

Public Utility Holding Company Act of 1935 (PUHCA) - Historically, Xcel Energy has been a registered holding company under the PUHCA. As a registered holding company, Xcel Energy, its utility subsidiaries and certain of its nonutility subsidiaries have been subject to extensive regulation by the SEC under the PUHCA with respect to numerous matters, including issuances and sales of securities, acquisitions and sales of certain utility properties, payments of dividends out of capital and surplus, and intra-system sales of certain nonpower goods and services. In addition, the PUHCA generally limited the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company.

On Aug. 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (Energy Act), significantly changing many federal statutes and repealing the PUHCA as of Feb. 8, 2006. However, as part of the repeal of the PUHCA, the FERC was given authority to review the books and records of holding companies and their nonutility subsidiaries to the extent relevant to the charges of jurisdictional utilities, authority to review service company cost allocations, and more authority over the merger and acquisition of public utilities. With the repeal of PUHCA, state commissions were given similar authority to review the books and records of holding companies and their nonutility subsidiaries. Despite these increases in the FERC s authority, Xcel Energy believes that the repeal of the PUHCA will lessen its regulatory burdens and give it more flexibility in the event it were to choose to expand its utility or nonutility businesses.

Besides repealing the PUHCA, 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 DOE. The FERC and the DOE are in various stages of rulemaking in implementing the Energy Policy Act. While the precise impact of these rulemakings cannot be determined at this time, Xcel Energy generally views the Energy Act as legislation that will enhance the utility industry going forward.

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 11.47 percent for NSP-Minnesota; 11.0 percent for NSP-Wisconsin; 10.75 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 the Midwest Independent Transmission System Operator, Inc. (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. Both bills and payments from MISO for participation in this centrally dispatched market are received, resulting in a net cost in serving Xcel Energy s native load obligation. This net result is recorded as a component of operating and maintenance expenses. The MPUC issued an interim order in April 2005 allowing MISO Day 2 charges to be recovered through the NSP-Minnesota Fuel Clause Adjustment (FCA) mechanism. In December 2005, the MPUC issued a second interim order approving the recovery of certain MISO charges through the FCA mechanism but requiring that additional charges either be recovered as part of a general rate case or through an annual review process outside the FCA mechanism, and requiring refunds of non-FCA costs. However, the December 2005 MPUC order also suspended the refund obligation until such time as it could reconsider the matter. On Feb. 9, 2006, the MPUC voted to reconsider its December 2005 order. The MPUC on reconsideration determined that parties be directed to determine which charges are appropriately in the FCA and which are more appropriately established in base rates and report back to the MPUC in 60 days; to grant deferred accounting treatment for costs ultimately determined to be included in base rates for a period of 36 months, with recovery of deferred amounts to be reviewed in a general rate case; and that amounts collected to date through the FCA under the April and December 2005 interim orders are not subject to refund. As a result, NSP-Minnesota will be allowed to recover its prudently incurred MISO costs either through existing fuel clause mechanisms or in base rates. In March 2005, the PSCW issued an interim order allowing NSP-Wisconsin deferred accounting treatment of MISO charges. However, the PSCW staff issued an interpretive memorandum in October 2005 asserting that certain MISO costs may not be recovered through the interim fuel cost mechanism and may not be deferrable.

NSP-Wisconsin and the other Wisconsin utilities contested the PSCW s interpretation in their November comments to the PSCW. To date, NSP-Wisconsin has deferred approximately $5.7 million of MISO Day 2 costs as a regulatory asset.

Xcel Energy has notified MISO that NSP-Minnesota and NSP-Wisconsin may seek to withdraw from MISO if rate recovery of Day 2 costs is not allowed. Withdrawal would require FERC approval and could require Xcel Energy to pay a withdrawal fee.

In addition, pursuant to FERC orders, NSP-Minnesota and NSP-Wisconsin are billed for certain MISO Day 2 charges associated with the loads of certain wholesale transmission service customers taking service under pre-MISO grandfathered agreements (GFAs). In March 2005, Xcel Energy filed for the FERC s approval to pass through these charges to GFA customers. FERC accepted the filing subject to refund and hearing procedures. In 2005, NSP-Minnesota and NSP-Wisconsin were billed for $1.1 million of MISO charges, which have not yet been recovered from GFA customers. The likelihood of full rate-recovery is uncertain at this time. In addition, Xcel Energy has filed an appeal of the FERC orders.

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 distribution system. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, in 2003 the CPUC and MPUC approved proposals to recover, through a rate surcharge, certain costs to upgrade generation plants and lower emissions in the Denver and Minneapolis-St. Paul metropolitan areas. These rate recovery mechanisms 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, nonregulated enterprises 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. Such changes could have a material effect on Xcel Energy s results of operations in the period the write-off is recorded.

At Dec. 31, 2005, Xcel Energy reported on its balance sheet regulatory assets of approximately $963 million and regulatory liabilities of approximately $1.7 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.

Pending and Recently Concluded Regulatory Proceedings

NSP-Minnesota Electric Rate Case In November 2005, NSP-Minnesota requested an electric rate increase of $168 million or 8.05 percent. This increase was based on a requested 11 percent return on common equity, a projected common equity ratio to total capitalization of 51.7 percent and a projected electric rate base of $3.2 billion. On Dec. 15, 2005, the MPUC authorized an interim rate increase of $147 million, subject to refund, which became effective on Jan. 1, 2006. The anticipated procedural schedule is as follows:

March 2nd Intervenor Direct Testimony

March 30th Rebuttal Testimony

April 13th Surrebuttal Testimony

April 20th April 28th Evidentiary Hearings

May 24th Initial Briefs

June 6th Reply Briefs

July 6th Administrative Law Judge Report

September 5th MPUC Order

NSP-Wisconsin 2006 General Rate Case In 2005, NSP-Wisconsin, requested an electric revenue increase of $58.3 million and a natural gas revenue increase of $8.1 million, based on a 2006 test year, an 11.9 percent return on equity and a common equity ratio of 56.32 percent. On Jan. 5, 2006, the PSCW approved an electric revenue increase of $43.4 million and a natural gas revenue increase of $3.9 million, based on an 11.0 percent return on equity and a 54-percent common equity ratio target. The new rates were effective Jan. 9, 2006. The order authorized the deferral of an additional $6.5 million in costs related to nuclear decommissioning and manufactured gas plant site clean up for recovery in the next rate case. The order also prohibits NSP-Wisconsin from paying dividends above $42.7 million, if its actual calendar year average common equity ratio is or will fall below 54.03 percent. It also imposes an asymmetrical electric fuel clause bandwidth of positive 2 percent to negative 0.5 percent outside of which NSP-Wisconsin would be permitted to request or be required to change rates.

PSCo Natural Gas Rate Case In 2005, PSCo filed for an increase of $34.5 million in natural gas base rates in Colorado, based on a return on equity of 11.0 percent with a common equity ratio of 55.49 percent.

On Jan. 19, 2006, the CPUC approved a settlement agreement between PSCo and other parties to the case. Final rates became effective Feb. 6, 2006. The terms of the settlement include:

- Natural gas revenue increase of $22 million;
- Return on common equity of 10.5 percent;
- Earnings over 10.5 percent return on common equity will be refunded back to customers;
- Common equity ratio of 55.49 percent; and
- Customer charges for the residential and commercial sales classes of $10 and $20 per month, respectively.

Tax Matters

Interest Expense Deductibility - PSCo s wholly owned subsidiary, PSR Investments, Inc. (PSRI), owns and manages permanent life insurance policies, known as COLI policies, on some of PSCo s employees. 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 1999. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2005, would reduce earnings by an estimated $361 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) are also included, the total exposure through Dec. 31, 2005, is approximately $428 million. Xcel Energy estimates its annual earnings for 2006 would be reduced by $44 million, after tax, which represents 10 cents per share, if COLI interest expense deductions were no longer available. See Note 14 to the Consolidated Financial Statements for further discussion.

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.

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:

$147 million in 2005;

$133 million in 2004; and

$133 million in 2003.

Xcel Energy expects to expense an average of approximately $176 million per year from 2006 through 2010 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 placed in service on environmental improvements at regulated facilities were approximately:

$37.1 million in 2005;

$20.9 million in 2004; and

$58.5 million in 2003.

The regulated utilities expect to incur approximately $438 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2006, and approximately $714 million of related expenditures during the period from 2007 through 2010. Included in these amounts are expenditures to reduce emissions of generating plants in Minnesota and Colorado. Approximately $347 million and $392 million of these expenditures, respectively, are related to modifications to reduce the emissions of NSP-Minnesota s generating plants located in the Minneapolis-St. Paul metropolitan area pursuant to the MERP, which are recoverable from customers through cost-recovery mechanisms. Expected expenditures related to environmental modifications on Comanche Units 1 and 2 are approximately $26 million in 2006 and $62 million during the period from 2007 through 2010. The remaining expected capital expenditures relate to various other environmental projects. See Note 14 to the Consolidated Financial Statements for further discussion of Xcel Energy s environmental contingencies.

The issue of global climate change is receiving increased attention. Debate continues concerning the extent to which the earth s climate is warming, the causes of climate variations that have been observed and the ultimate impact that might result from a changing climate. There also is considerable debate regarding public policy for the approach that the United States should follow to address the issue. The United Nations-sponsored Kyoto Protocol, which establishes greenhouse gas reduction targets for developed nations, entered into force on Feb. 16, 2005. President Bush has declared that the United States will not ratify the protocol and is opposed to legislative mandates, preferring a program based on voluntary efforts and research on new technologies. Xcel Energy is closely monitoring the issue from both scientific and policy perspectives. While it is not possible to know the eventual outcome, Xcel Energy believes the issue merits close attention and is taking actions it believes are prudent to be best positioned for a variety of possible outcomes. 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, the evaluation process for future generating resources incorporates the risk of future carbon limits through the use of a carbon cost adder or externality costs. Xcel Energy also is involved in other projects to improve available methods for managing carbon.

Impact of Nonregulated Investments

In the past, Xcel Energy s investments in nonregulated operations have 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 such a significant impact on its results. Xcel Energy does not expect to make any material investments in nonregulated projects.

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 appropriate technical 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, in and of themselves, could materially impact the Consolidated Financial Statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the Consolidated Financial Statements and related disclosures, 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, 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	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 Ability to realize tax benefits through carry backs to prior periods or carry overs to future periods	Management s Discussion and Analysis: Factors Affecting Results of Continuing Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 8 and 14
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 10
Asset Valuation	Regional economic conditions affecting asset operation, market prices and related cash flows Regulatory and political environments and requirements	Management s Discussion and Analysis: Results of Operations Statement of Operations Analysis Discontinued Operations Factors Affecting Results of Continuing Operations

Levels of future market penetration and customer growth	Impact of Nonregulated Investments Notes to Consolidated Financial Statements Note 2

Xcel Energy continually makes informed 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.

Future cash inflows of operations are projected in order to assess whether they will be sufficient to recover future cash outflows, including the impact of product price changes and market penetration to customer groups.

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, 2005.

Recently Implemented Accounting Changes

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

Pending Accounting Changes

Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004) Share Based Payment (SFAS No. 123R) In December 2004, the FASB issued SFAS No. 123R related to equity-based compensation. This statement replaces the original SFAS No. 123 Accounting for Stock-Based Compensation. Under SFAS No. 123R, companies are no longer allowed to account for their share-based payment awards using the intrinsic value allowed by previous accounting requirements, which did not require any expense to be recorded on stock options granted with an equal to or greater than fair market value exercise price. Instead, equity-based compensation arrangements will be measured and recognized based on the grant-date fair value using an option-pricing model (such as Black-Scholes or Binomial) that considers at least six factors identified in SFAS No. 123R. An expense related to the difference between the grant-date fair value and the purchase price would be recognized over the vesting period of the options. Under previous guidance, companies were allowed to initially estimate forfeitures or recognize them as they actually occurred. SFAS No. 123R requires companies to estimate forfeitures on the date of grant and to adjust that estimate when information becomes available that suggests actual forfeitures will differ from previous estimates. Revisions to forfeiture estimates will be recorded as a cumulative effect of a change in accounting estimate in the period in which the revision occurs.

Previous accounting guidance allowed for compensation expense related to performance share plans to be reversed if the target was not met. However, under SFAS No. 123R, compensation expense for performance share plans that expire unexercised due to the company s failure to reach a certain target stock price cannot be reversed. Any accruals made for Xcel Energy s restricted stock unit plan that were granted in 2004 and based on a total shareholder return could not be reversed if the target was not met. Implementation of SFAS No. 123R is required for annual periods beginning after June 15, 2005. Xcel Energy is required to adopt the provisions in the first quarter of 2006. Implementation is not expected to have a material impact on net income or earnings per share.

Accounting for Uncertain Tax Positions In July 2004, the FASB discussed potential changes or clarifications in the criteria for recognition of income tax benefits, which may result in raising the threshold for recognizing tax benefits that have some degree of uncertainty. In July 2005, the FASB issued an exposure draft on accounting for uncertain tax positions under SFAS No. 109 Accounting for Income Taxes. As issued, the exposure draft would have been effective Dec. 31, 2005, and only tax benefits that meet the probable recognition threshold would be recognized or continue to be recognized on the effective date. Initial derecognition amounts would be reported as a cumulative effect of a change in accounting principle.

Subsequent to the comment period that closed in September 2005, the FASB announced that the effective date of its new interpretation will be delayed, with a revised pronouncement to be released no earlier than the first quarter of 2006. In redeliberations in November 2005, the FASB decided that the benefit recognition approach in the exposure draft should be retained, but that the initial recognition threshold should be more likely than not rather than probable. In redeliberations on Jan. 11, 2006, the FASB addressed the issues of transition and effective date. For Xcel Energy, the new interpretation, if and when issued, is likely to be effective beginning Jan. 1, 2007, with any cumulative effect of the change reflected in retained earnings.

Although Xcel Energy has not assessed the impact of a new recognition threshold on all of its open tax positions, based on available information, it believes that its COLI tax position meets the more likely than not threshold, and therefore it plans to continue to recognize all COLI tax benefits in full. See Factors Affecting Results of Continuing Operations Tax Matters for further discussion of this matter.

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.

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 are primarily focused on specific regions where market knowledge and experience have been obtained and are generally less than one year in length. Xcel Energy s risk-management policy allows management to conduct these activities within approved guidelines and limitations as approved by the Company s 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, as amended (SFAS No. 133).

The fair value of the commodity trading contracts as of Dec. 31, 2005, was as follows:

(Millions of Dollars)		
Fair value of trading contracts outstanding at Jan. 1, 2005	$	
Contracts realized or settled during the year		(6.1)
Fair value of trading contract additions and changes during the year		10.0
Fair value of contracts outstanding at Dec. 31, 2005	$	3.9

As of Dec. 31, 2005, 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	$ 663	$	$	$	$ 663
	2	15	1,109	322		1,446
PSCo	1	1,352				1,352
	2	1,382	261			1,643
Total futures/forwards fair value		$ 3,412	$ 1,370	$ 322	$	$ 5,104

73

		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	$ (251)	$	$	$	$ (251)
PSCo	2	(922)				(922)
Total options fair value		$ (1,173)	$	$	$	$ (1,173)

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	2	$ 2,927	$	$	$	$ 2,927
PSCo	2	1,944				1,944
Total futures/forwards fair value		$ 4,871	$	$	$	$ 4,871

		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	$ (583)	$	$	$	$ (583)
NSP-Wisconsin	2	726				726
PSCo	2	(1,954)	1,036			(918)
Total options fair value		$ (1,811)	$ 1,036	$	$	$ (775)

1 Prices actively quoted or based on actively quoted prices.

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

Normal purchases and sales transactions, as defined by 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 included in the commodity trading operations and are not qualifying hedges.

At Dec. 31, 2005, a 10-percent increase in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.7 million, whereas a 10-percent decrease would increase pretax income from continuing operations by approximately $0.8 million.

Xcel Energy s short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, 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.

As of Dec. 31, 2005, the VaRs for the commodity trading operations were:

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

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

As of Dec. 31, 2004, the VaRs for the commodity trading operations were:

(Millions of Dollars)	Year ended Dec. 31, 2004	During 2004 Average	High	Low
Commodity trading (a)	$ 0.29	$ 0.97	$ 2.09	$ 0.27

(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 a recognized asset, liability or firm commitment. 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 related hedged assets, liabilities or firm commitments. 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, 2005 and 2004, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $10.3 million and $6.8 million, respectively. See Note 12 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 Nuclear Regulatory Commission (NRC), to fund certain costs of nuclear decommissioning, which are subject to interest rate risk and equity price risk. As of Dec. 31, 2005 and 2004, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. Per NRC mandates, 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 In addition to the risks discussed previously, Xcel Energy and its subsidiaries are 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 when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

At Dec. 31, 2005, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $44.2 million, while a decrease of 10 percent would have resulted in a decrease of $41.1 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	2005	2004	2003
Cash provided by (used in) operating activities			
Continuing operations	$ 1,131	$ 1,128	$ 1,106
Discontinued operations	53	(315)	275
Total	$ 1,184	$ 813	$ 1,381

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.

Cash provided by operating activities for continuing operations increased $22 million during 2004 compared with 2003 due to the timing of payments made for trade payables partially offset by increased inventory costs related to higher natural gas costs, which will be collected from customers in future periods. Cash provided by operating activities for discontinued operations decreased $590 million during 2004 compared with 2003. During 2004, Xcel Energy paid $752 million pursuant to the NRG settlement agreement, which was partially offset by tax benefits received.

(Millions of Dollars)	2005	2004	2003
Cash provided by (used in) investing activities			
Continuing operations	$ (1,362)	$ (1,268)	$ (1,055)
Discontinued operations	136	37	126
Total	$ (1,226)	$ (1,231)	$ (929)

Cash used in investing activities for continuing operations increased $94 million during 2005 compared with 2004, primarily due to increased 2005 utility capital expenditures and restricted cash released in 2004. Cash provided by investing activities for discontinued operations increased $99 million during 2005 compared with 2004, 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 $213 million during 2004 compared with 2003, primarily due to increased utility capital expenditures. Cash provided by investing activities for discontinued operations decreased $89 million during 2004 compared with 2003, primarily due to the receipt of proceeds from the sale of Viking in 2003.

(Millions of Dollars)	2005	2004	2003
Cash provided by (used in) financing activities			
Continuing operations	$ 111	$ (111)	$ (346)
Discontinued operations			(21)

Total	$ 111	$ (111)	$ (367)

Cash flow from financing activities related to continuing operations increased $222 million during 2005 compared with 2004, primarily due to increased short-term borrowings.

Cash flow from financing activities related to continuing operations increased $235 million during 2004 compared with 2003, primarily due to increased short-term borrowings partially offset by a common stock repurchase.

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, Nonregulated Investments 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 2006, 2007 and 2008 are shown in the table below.

(Millions of Dollars)	2006	2007	2008
Electric utility	$ 1,386	$ 1,381	$ 1,169
Natural gas utility	110	113	132
Common utility	84	81	81
Total utility	1,580	1,575	1,382
Other nonregulated			2
Total capital expenditures	1,580	1,575	1,384
Debt maturities	835	339	632
Total capital requirements	$ 2,415	$ 1,914	$ 2,016

The capital expenditure forecast includes PSCo s share of the 750-megawatt Comanche 3 coal-fired plant in Colorado and the MERP project, which will reduce the emissions of three of NSP-Minnesota s generating plants. The MERP project is expected to cost approximately $1 billion, with major construction starting in 2005 and finishing in 2009. Xcel Energy began recovering the costs of the emission-reduction project through customer rate increases effective Jan. 1, 2006. Comanche 3 is expected to cost approximately $1.35 billion, with major construction starting in 2006 and finishing in 2010. The CPUC has approved sharing one-third ownership of this plant with other parties. Consequently, Xcel Energy s capital expenditure forecast includes $1 billion, approximately two-thirds of the total cost.

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, 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 requirements 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 commercial 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, 2005. See additional discussion in the Consolidated Statements of Capitalization and Notes 3, 4, 13 and 14 to the Consolidated Financial Statements.

	Payments Due by Period				
(Thousands of Dollars)	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Long-term debt, principal and interest payments	$ 10,387,694	$ 1,236,074	$ 1,672,323	$ 2,148,700	$ 5,330,597

Capital lease obligations	98,684	6,447	12,426	11,794	68,017
Operating leases (a)	208,249	41,376	64,589	48,055	54,229
Unconditional purchase obligations (b)	11,972,606	2,573,587	2,639,833	2,057,622	4,701,564
Other long-term obligations	265,925	38,213	55,376	52,706	119,630
Payments to vendors in process	129,315	129,315			
Short-term debt	746,120	746,120			
Total contractual cash obligations (c)	$ 23,808,593	$ 4,771,132	$ 4,444,547	$ 4,318,877	$ 10,274,037

(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, 2005, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $110.8 million.

(b) Obligations to purchase fuels for electric generation plants, and electricity and natural gas for resale. Certain contractual purchase obligations are adjusted based on indexes. 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 $600 million of goods and services through the year 2020, 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 deliver the financial results that will enable the board of directors to grant annual dividend increases 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. Under the PUHCA, unless there was an order from the SEC, a holding company or any subsidiary could only declare and pay dividends out of retained earnings. Xcel Energy had $562 million of retained earnings at Dec. 31, 2005, and expects to declare dividends as scheduled. With the repeal of the PUHCA, this limitation on a holding company s dividends will no longer apply. Notwithstanding the repeal of the PUHCA, federal law will still limit 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 the 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, i.e., 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, 2005, was 84 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy s ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of Xcel Energy common stock.

Capital Sources

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

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, were limited under PUHCA in their ability to issue securities. Registered holding companies and their subsidiaries could not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy did not qualify for any of the main exemptive rules, it had received financing authority from the SEC under the PUHCA for various financing arrangements. Xcel Energy s current financing authority permits it, subject to certain conditions, to issue through June 30, 2008, up to $1.8 billion of new long-term debt, common equity and equity-linked securities, and $1.0 billion of short-term debt securities during the new authorization period, provided that the aggregate amount of long-term debt, common equity, and equity-linked and short-term debt securities issued during the new authorization period does not exceed $2.0 billion.

Xcel Energy s ability to issue securities under the financing authority was subject to a number of conditions. One of the conditions of the financing authority was that Xcel Energy s consolidated ratio of common equity to total capitalization be at least 30 percent. As of Dec. 31, 2005, the common equity ratio was approximately 42 percent. Additional conditions require that a security to be issued, must be at least rated investment grade by one nationally recognized rating agency. Finally, all outstanding securities that are rated must be rated investment grade by at least one nationally recognized rating agency. On Feb. 10, 2006, Xcel Energy s senior unsecured debt was considered investment grade by Standard & Poor s Ratings Services (Standard & Poor s), Moody s and Fitch Ratings (Fitch).

Upon the repeal of the PUHCA, these limitations on Xcel Energy s financings generally will no longer apply, nor will the PUHCA restrictions generally apply to the financings by the utility subsidiaries. However, utility financings and intra-system financing will become subject to the jurisdiction of the FERC under the Federal Power Act. The FERC has granted a blanket authorization for certain intra-system financings involving holding companies. Requests to the FERC to clarify its rules or grant similar blanket authorizations are presently pending before the FERC. Xcel Energy and the utility subsidiaries are presently evaluating the specific applications that they will need to file with FERC due to repeal of the PUHCA.

It is possible that in lieu of requesting authority from the FERC for intra-system financings, Xcel Energy and the utility subsidiaries may rely in the interim on a transitional savings clause that would permit such financing transactions to the extent authorized by the SEC financing order and so long as the conditions in the SEC financing order continue to be satisfied.

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. 14, 2006, 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	$ 450	$ 162.7	$ 287.3	$	$ 287.3	April 2010
NSP-Wisconsin						
PSCo	600	212.0	388.0	49.2	437.2	April 2010
PSCo	50		50.0		50.0	April 2006
SPS	250	82.0	168.0	12.7	180.7	April 2010
Xcel Energy -holding company	700	393.5	306.5	0.8	307.3	November 2009
Total	$ 2,050	$ 850.2	$ 1,199.8	$ 62.7	$ 1,262.5	

* Includes direct borrowings, 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 and industry deregulation; 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. 23, 2006, the following represents the credit ratings assigned to various Xcel Energy companies:

79

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 13 to the Consolidated Financial Statements. Xcel Energy has no explicit rating triggers in its debt agreements.

Money Pool Xcel Energy has established a utility money pool arrangement with the utility subsidiaries and received 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. 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 utility money pool pursuant to approval from their respective state regulatory commissions. No borrowings or loans were outstanding at Dec. 31, 2005. Borrowing limits are $250 million, $250 million and $100 million, respectively. As a consequence of the repeal of PUHCA and the recent amendments to section 203 of the Federal Power Act, it may be necessary for Xcel Energy and the utility subsidiaries to submit its existing money pool arrangement to FERC for its approval. Xcel Energy and the utility subsidiaries are presently evaluating the situation.

Registration Statements Xcel Energy s Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2005, Xcel Energy had approximately 403 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, 2005, 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:

In February 2002, Xcel Energy filed a $1 billion shelf registration with the SEC. Xcel Energy may issue debt securities, common stock and rights to purchase common stock under this shelf registration. Xcel Energy has approximately $482.5 million remaining under this registration. Xcel Energy has approximately $400 million remaining under the $1 billion unsecured debt shelf registration filed with the SEC in 2000.

On March 22, 2005, NSP-Minnesota filed a shelf registration statement with the SEC to register an additional $1 billion of secured or unsecured debt securities, which may be issued from time to time in the future. This registration became effective on April 7, 2005, and supplements the $40 million of debt securities previously registered with the SEC. After issuance of $250 million of first mortgage bonds in July 2005, as discussed later, $790 million remains available under the currently effective registration statement.

PSCo has an effective shelf registration statement with the SEC under which $800 million of secured first collateral trust bonds or unsecured senior debt securities were registered. PSCo has approximately $225 million remaining under this registration.

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments primarily through internally generated funds. Xcel Energy plans to refinance existing long-term debt or scheduled long-term debt maturities at each of the regulated operating utilities based on prevailing market conditions. To facilitate potential long-term debt issuances at the utility subsidiaries, SPS intends to file a long-term debt shelf registration statement with the SEC for up to $500 million in 2006, and NSP-Wisconsin may file a long-term debt shelf registration for up to $100 million.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements 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 2006 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

	2006 Diluted Earnings Per Share Range
Utility operations	$1.25 - $1.35
COLI tax benefit	0.10
Other nonregulated subsidiaries	(0.10)
Xcel Energy Continuing Operations	**$1.25 - $1.35**

Key Assumptions for 2006:

Normal weather patterns are experienced;

Reasonable rate recovery is approved in the Minnesota electric rate case;

Weather-adjusted retail electric utility sales grow by approximately 1.3 percent to 1.7 percent;

Weather-adjusted retail natural gas utility sales grow by approximately 0.0 percent to 1.0 percent;

Short-term wholesale and commodity trading margins are projected to be within a range of approximately $30 million to $50 million;

Other utility operating and maintenance expenses increase between 3 percent and 4 percent from 2005 levels;

Depreciation expense increases approximately $100 million to $110 million, which includes increases in decommissioning accruals that are expected to be recovered through rates approved in the Minnesota electric rate case;

Interest expense increases approximately $10 million to $15 million from 2005 levels;

Allowance for funds used during construction recorded for equity financing is expected to increase approximately $10 million to $15 million from 2005 levels;

Xcel Energy continues to recognize COLI tax benefits;

The effective tax rate for continuing operations is approximately 27 percent to 29 percent; and

Average common stock and equivalents total approximately 428 million shares, based on the If Converted method for convertible notes.

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 20 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, 2005. 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, 2005, 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 24, 2006

/S/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
February 24, 2006

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*, that Xcel Energy Inc. and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2005, 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, 2005, 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, 2005, 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, 2005 of the Company and our report dated February 24, 2006 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 24, 2006

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, 2005 and 2004, and the related consolidated statements of operations, common stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. 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 these 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, 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 24, 2006 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 24, 2006

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Thousands of Dollars, except per share data)

	Year ended Dec. 31 2005	2004	2003
Operating revenues			
Electric utility	$ 7,243,637	$ 6,225,245	$ 5,919,938
Natural gas utility	2,307,385	1,915,514	1,677,768
Nonregulated and other	74,455	74,802	133,561
Total operating revenues	9,625,477	8,215,561	7,731,267
Operating expenses			
Electric fuel and purchased power utility	3,922,163	3,040,759	2,705,839
Cost of natural gas sold and transported utility	1,823,123	1,445,773	1,190,996
Cost of sales nonregulated and other	24,676	28,757	80,683
Other operating and maintenance expenses utility	1,679,172	1,591,718	1,570,492
Other operating and maintenance expenses nonregulated	28,493	44,109	53,485
Depreciation and amortization	767,321	705,955	727,307
Taxes (other than income taxes)	287,810	282,775	278,034
Total operating expenses	8,532,758	7,139,846	6,606,836
Operating income	1,092,719	1,075,715	1,124,431
Interest and other income (expense) net (see Note 11)	857	9,316	(5,234)
Allowance for funds used during construction equity	21,627	33,648	25,338
Interest charges and financing costs			
Interest charges (includes other financing costs of $25,829, $27,296 and $31,992, respectively)	463,370	458,294	448,690
Allowance for funds used during construction debt	(20,744)	(23,814)	(20,402)
Distributions on redeemable preferred securities of subsidiary trusts			22,731
Total interest charges and financing costs	442,626	434,480	451,019
Income from continuing operations before income taxes	672,577	684,199	693,516
Income taxes	173,539	161,935	170,692
Income from continuing operations	499,038	522,264	522,824
Income (loss) from discontinued operations net of tax (see Note 2)	13,934	(166,303)	99,568
Net income	512,972	355,961	622,392
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available to common shareholders	$ 508,731	$ 351,720	$ 618,151
Weighted average common shares outstanding (in thousands)			
Basic	402,330	399,456	398,765
Diluted	425,671	423,334	418,912
Earnings (loss) per share basic			
Income from continuing operations	$ 1.23	$ 1.30	$ 1.30
Income (loss) from discontinued operations (see Note 2)	0.03	(0.42)	0.25
Earnings per share	$ 1.26	$ 0.88	$ 1.55
Earnings (loss) per share diluted			
Income from continuing operations	$ 1.20	$ 1.26	$ 1.26
Income (loss) from discontinued operations (see Note 2)	0.03	(0.39)	0.24
Earnings per share	$ 1.23	$ 0.87	$ 1.50

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)

	Year ended Dec. 31 2005	2004	2003
Operating activities			
Net income	$ 512,972	$ 355,961	$ 622,392
Remove (income) loss from discontinued operations	(13,934)	166,303	(99,568)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	782,074	739,025	757,838
Nuclear fuel amortization	45,330	43,296	43,401
Deferred income taxes	205,058	57,273	100,869
Amortization of investment tax credits	(11,620)	(12,189)	(12,439)
Allowance for equity funds used during construction	(21,627)	(33,648)	(25,338)
Undistributed equity in earnings of unconsolidated affiliates	(712)	(3,342)	(4,833)
Impairment of assets	2,887		8,856
Unrealized gain (loss) on derivative financial instruments	(3,923)	6,206	2,404
Change in accounts receivable	(250,305)	(123,044)	(129,408)
Change in inventories	(94,605)	(46,220)	(911)
Change in other current assets	(289,250)	(190,827)	(174,793)
Change in accounts payable	281,430	133,278	106,087
Change in other current liabilities	30,923	2,494	(4,855)
Change in other noncurrent assets	(81,506)	(6,485)	(142,849)
Change in other noncurrent liabilities	37,242	39,669	59,306
Operating cash flows (used in) provided by discontinued operations	53,283	(314,575)	274,582
Net cash provided by operating activities	1,183,717	813,175	1,380,741
Investing activities			
Utility capital/construction expenditures	(1,304,468)	(1,274,290)	(944,421)
Allowance for equity funds used during construction	21,627	33,648	25,338
Purchase of investments in external decommissioning fund	(576,001)	(305,328)	(144,367)
Proceeds from the sale of investments in external decommissioning fund	494,529	228,676	61,031
Nonregulated capital expenditures and asset acquisitions	(6,976)	(2,122)	(2,055)
Proceeds from sale of assets	11,228		
Equity investments, loans, deposits and sales of nonregulated projects		(4,082)	10,588
Restricted cash	(6,226)	42,628	(38,488)
Other investments	5,075	12,474	(22,380)
Investing cash flows provided by discontinued operations	135,577	37,119	125,904
Net cash used in investing activities	(1,225,635)	(1,231,277)	(928,850)
Financing activities			
Short-term borrowings net	433,820	253,737	(428,580)
Proceeds from issuance of long-term debt	2,529,408	419,848	1,689,317
Repayment of long-term debt, including reacquisition premiums	(2,517,698)	(438,595)	(1,307,012)
Proceeds from issuance of common stock	9,085	6,985	3,219
Repurchase of common stock		(32,023)	
Dividends paid	(343,092)	(320,444)	(303,316)
Financing cash flows (used in) provided by discontinued operations	(200)	(200)	(20,500)
Net cash (used in) provided by financing activities	111,323	(110,692)	(366,872)
Net increase (decrease) in cash and cash equivalents	69,405	(528,794)	85,019
Net increase (decrease) in cash and cash equivalents discontinued operations	(20,570)	(12,018)	6,510
Net increase in cash and cash equivalents adoption of FIN No. 46		3,439	
Cash and cash equivalents at beginning of year	23,361	560,734	469,205
Cash and cash equivalents at end of year	$ 72,196	$ 23,361	$ 560,734
Supplemental disclosure of cash flow information			

Cash paid for interest (net of amounts capitalized)	$	417,016	$	423,673	$	402,506
Cash paid for income taxes (net of refunds received)	$	10,625	$	(355,639)	$	(6,379)

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)

	Dec. 31 2005	2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,196	$ 23,361
Accounts receivable net of allowance for bad debts: $39,798 and $34,299, respectively	1,011,569	761,264
Accrued unbilled revenues	614,016	435,431
Materials and supplies inventories at average cost	159,560	161,323
Fuel inventory at average cost	64,987	64,265
Natural gas inventories at average cost	310,610	214,964
Recoverable purchased natural gas and electric energy costs	395,070	264,628
Derivative instruments valuation at market	213,138	129,218
Prepayments and other	99,904	149,538
Current assets held for sale and related to discontinued operations	200,811	367,248
Total current assets	3,141,861	2,571,240
Property, plant and equipment, at cost:		
Electric utility plant	18,870,516	18,236,957
Natural gas utility plant	2,779,043	2,617,552
Common utility and other property	1,518,266	1,476,553
Construction work in progress	783,490	721,335
Total property, plant and equipment	23,951,315	23,052,397
Less accumulated depreciation	(9,357,414)	(9,050,636)
Nuclear fuel net of accumulated amortization: $1,190,386 and $1,145,228, respectively	102,409	74,308
Net property, plant and equipment	14,696,310	14,076,069
Other assets:		
Nuclear decommissioning fund and other investments	1,145,659	1,023,481
Regulatory assets	963,403	850,636
Derivative instruments valuation at market	451,937	424,786
Prepaid pension asset	683,649	642,873
Other	164,212	175,174
Noncurrent assets held for sale and related to discontinued operations	401,285	540,584
Total other assets	3,810,145	3,657,534
Total assets	$ 21,648,316	$ 20,304,843
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 835,495	$ 223,655
Short-term debt	746,120	312,300
Accounts payable	1,187,489	903,609
Taxes accrued	235,056	216,439
Dividends payable	87,788	83,405
Derivative instruments valuation at market	191,414	135,098
Other	345,807	348,557
Current liabilities held for sale and related to discontinued operations	43,657	112,931
Total current liabilities	3,672,826	2,335,994
Deferred credits and other liabilities:		
Deferred income taxes	2,191,794	2,065,665
Deferred investment tax credits	131,400	143,028
Regulatory liabilities	1,710,820	1,630,545
Derivative instruments valuation at market	499,390	450,883
Asset retirement obligations	1,292,006	1,091,089
Customer advances	310,092	303,928
Minimum pension liability	88,280	62,669
Benefit obligations and other	343,201	327,662
Noncurrent liabilities held for sale and related to discontinued operations	6,936	89,242
Total deferred credits and other liabilities	6,573,919	6,164,711
Minority interest in subsidiaries	3,547	3,220
Commitments and contingencies (see Note 14)		

Capitalization (see Statements of Capitalization):				
Long-term debt		5,897,789		6,493,020
Preferred stockholders equity		104,980		104,980
Common stockholders equity		5,395,255		5,202,918
Total liabilities and equity	$	21,648,316	$	20,304,843

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(Thousands)

	Common Stock Issued		Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
	Shares	Par Value				
Balance at Dec. 31, 2002	398,714	$ 996,785	$ 4,038,151	$ (100,942)	$ (269,010)	$ 4,664,984
Net income				622,392		622,392
Currency translation adjustments					182,829	182,829
Minimum pension liability					9,710	9,710
Net derivative instrument fair value changes during the period (see Note 12)					(14,005)	(14,005)
Unrealized gain marketable securities					340	340
Comprehensive income for 2003						801,266
Dividends declared:						
Cumulative preferred stock			(720)	(3,181)		(3,901)
Common stock			(149,521)	(149,606)		(299,127)
Issuances of common stock	251	627	2,591			3,218
Balance at Dec. 31, 2003	398,965	$ 997,412	$ 3,890,501	$ 368,663	$ (90,136)	$ 5,166,440
Net income				355,961		355,961
Currency translation adjustments					(3)	(3)
Minimum pension liability					(7,935)	(7,935)
Net derivative instrument fair value changes during the period (see Note 12)					(8,024)	(8,024)
Unrealized gain marketable securities					164	164
Comprehensive income for 2004						340,163
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(323,742)		(323,742)
Issuances of common stock	3,297	8,243	48,078			56,321
Purchases for restricted stock issuance	(1,800)	(4,500)	(27,523)			(32,023)
Balance at Dec. 31, 2004	400,462	$ 1,001,155	$ 3,911,056	$ 396,641	$ (105,934)	$ 5,202,918
Net income				512,972		512,972
Minimum pension liability					(17,271)	(17,271)
Net derivative instrument fair value changes during the period (see Note 12)					(8,919)	(8,919)
Unrealized gain marketable securities					63	63
Comprehensive income for 2005						486,845
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)

Common stock				(343,234)		(343,234)
Issuances of common stock	2,925	7,313	45,654			52,967
Balance at Dec. 31, 2005	403,387	$ 1,008,468	$ 3,956,710	$ 562,138	$ (132,061)	$ 5,395,255

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars)

Long-Term Debt	**Dec. 31 2005**	**2004**
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Dec. 1, 2005, 6.125%	$	$ 70,000
Dec. 1, 2006, 4.1% (a)	2,420	4,750
Dec. 1, 2006-2008, 4.5%-5% (a)	7,490	9,790
Aug. 1, 2006, 2.875%	200,000	200,000
Aug. 1, 2010, 4.75%	175,000	175,000
Aug. 28, 2012, 8%	450,000	450,000
March 1, 2019, 8.5% (b)	27,900	27,900
Sept. 1, 2019, 8.5% (b)	100,000	100,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
April 1, 2030, 8.5% (b)	69,000	69,000
July 15, 2035, 5.25%	250,000	
Senior Notes, due Aug. 1, 2009, 6.875%	250,000	250,000
Borrowings under credit facility, due April 2010, 5.05%	250,000	
Retail Notes, due July 1, 2042, 8%	185,000	185,000
Other	519	367
Unamortized discount-net	(7,278)	(7,759)
Total	2,360,051	1,934,048
Less current maturities	204,833	74,685
Total NSP-Minnesota long-term debt	$ 2,155,218	$ 1,859,363
PSCo		
First Mortgage Bonds, Series due:		
Nov. 1, 2005, 6.375%	$	$ 134,500
June 1, 2006, 7.125%	125,000	125,000
April 1, 2008, 5.625% (b)		18,000
Oct. 1, 2008, 4.375%	300,000	300,000
June 1, 2012, 5.5% (b)		50,000
Oct. 1, 2012, 7.875%	600,000	600,000
March 1, 2013, 4.875%	250,000	250,000
April 1, 2014, 5.5%	275,000	275,000
April 1, 2014, 5.875% (b)		61,500
Sept. 1, 2017, 4.375% (b)	129,500	
Jan. 1, 2019, 5.1% (b)	48,750	48,750
Jan. 1, 2024, 7.25%		110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000
Secured Medium-Term Notes, due March 5, 2007, 7.11%	100,000	100,000
Capital lease obligations, 11.2% due in installments through 2028	47,581	48,935
Unamortized discount	(3,524)	(5,870)
Total	2,072,307	2,315,815
Less current maturities	126,334	135,854
Total PSCo long-term debt	$ 1,945,973	$ 2,179,961
SPS		
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	$ 500,000	$ 500,000
Unsecured Senior A Notes, due March 1, 2009, 6.2%	100,000	100,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000

Pollution control obligations, securing pollution control revenue bonds, due:				
July 1, 2011, 5.2%		44,500		44,500
July 1, 2016, 3.58% at Dec. 31, 2005, and 2% at Dec. 31, 2004		25,000		25,000
Sept. 1, 2016, 5.75%		57,300		57,300
Unamortized discount		(1,024)		(1,338)
Total		825,776		825,462
Less current maturities		500,000		
Total SPS long-term debt	$	325,776	$	825,462

See Notes to Consolidated Financial Statements.

(Thousands of Dollars)		Dec. 31 2005		2004
Long-Term Debt - continued				
NSP-Wisconsin				
First Mortgage Bonds, Series due:				
Oct. 1, 2018, 5.25%	$	150,000	$	150,000
Dec. 1, 2026, 7.375%		65,000		65,000
Senior Notes due, Oct. 1, 2008, 7.64%		80,000		80,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% (a)		18,600		18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%		828		862
Unamortized discount		(919)		(985)
Total		313,509		313,477
Less current maturities		34		34
Total NSP-Wisconsin long-term debt	$	313,475	$	313,443
Other Subsidiaries				
Various Eloigne Co. Affordable Housing Project Notes, due 2007-2045, 0% 9.89%	$	95,692	$	110,412
Other		2,217		9,830
Total		97,909		120,242
Less current maturities		4,294		13,082
Total other subsidiaries long-term debt	$	93,615	$	107,160
Xcel Energy Inc.				
Unsecured senior notes, Series due:				
July 1, 2008, 3.4%	$	195,000	$	195,000
Dec. 1, 2010, 7%		600,000		600,000
Convertible notes, Series due:				
Nov. 21, 2007, 7.5%		230,000		230,000
Nov. 21, 2008, 7.5%		57,500		57,500
Borrowings under credit facility, due November 2009, 3.09%				140,000
Fair value hedge, carrying value adjustment		(14,073)		(8,333)
Unamortized discount		(4,695)		(6,536)
Total Xcel Energy Inc. debt	$	1,063,732	$	1,207,631
Total long-term debt from continuing operations	$	5,897,789	$	6,493,020
Long-Term Debt from Discontinued Operations				
First Mortgage Bonds Cheyenne:				
Due Jan. 1, 2024, 7.5%	$		$	7,800
Industrial Development Revenue Bonds, due Sept. 1, 2021-March 1, 2027, variable rate, 2.12% at Dec. 31, 2004				17,000
Total long-term debt from discontinued operations	$		$	24,800
Cumulative Preferred Stock authorized 7,000,000 shares of $100 par value; outstanding shares: 2005: 1,049,800; 2004: 1,049,800				
$3.60 series, 275,000 shares	$	27,500	$	27,500
$4.08 series, 150,000 shares		15,000		15,000
$4.10 series, 175,000 shares		17,500		17,500
$4.11 series, 200,000 shares		20,000		20,000
$4.16 series, 99,800 shares		9,980		9,980
$4.56 series, 150,000 shares		15,000		15,000
Total preferred stockholders equity	$	104,980	$	104,980
Common Stockholders Equity				
Common stock authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2005: 403,387,159; 2004: 400,461,804	$	1,008,468	$	1,001,155
Capital in excess of par value on common stock		3,956,710		3,911,056
Retained earnings		562,138		396,641
Accumulated other comprehensive income (loss)		(132,061)		(105,934)

Total common stockholders equity	$ 5,395,255	$ 5,202,918

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements.

90

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

On Aug. 8, 2005, President Bush signed into law the Energy Act, significantly changing many federal energy statutes. The Energy Act is expected to have a substantial long-term effect on energy markets, energy investment, and regulation of public utilities and holding company systems by the FERC, the SEC and the DOE. The FERC was directed by the Energy Act to address many areas previously regulated by other governmental entities under the statutes and determine whether changes to such previous regulations are warranted. The issues that the FERC has been required to consider associated with the repeal of the PUHCA include, but are not limited to, the expansion of the FERC authority to review mergers and sales of public utility companies and the expansion of the FERC authority over the books and records of holding companies and public utility companies previously governed by the SEC and the appropriate cost standard for the provision of non-power goods and services by service companies. The FERC is in various stages of rulemaking on these and other issues. Xcel Energy cannot predict the impact the new rulemakings will have on its operations or financial results, if any.

Principles of Consolidation In 2005, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 10 states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. Along with WGI, an interstate natural gas pipeline, these companies comprise our continuing regulated utility operations.

Xcel Energy s nonregulated subsidiaries in continuing operations include Eloigne Co. (investments in rental housing projects that qualify for low-income housing reported tax credits). Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Energy Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc. and Xcel Energy O&M Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Discontinued utility operations include the activity of Viking, an interstate natural gas pipeline company that was sold in January 2003; BMG, a regulated natural gas and propane distribution company that was sold in October 2003; and Cheyenne, a regulated electric and natural gas utility that was sold in January 2005. See Note 2 to the Consolidated Financial Statements for more information on the discontinued operations of Viking, BMG and Cheyenne.

During 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of UE (engineering, construction and design) and Quixx Corp. (a former subsidiary of UE that partners in cogeneration projects). During 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren (broadband telecommunications services). During 2003, Planergy International, Inc. (energy management solutions) closed and began selling a majority of its business operations, with final dissolution occurring in 2004. During 2003, Xcel Energy also divested its ownership interest in NRG, an independent power producer. On May 14, 2003, NRG filed for bankruptcy to restructure its debt. As a result of the reorganization, Xcel Energy relinquished its ownership interest in NRG. During 2003, the board of directors of Xcel Energy also approved management s plan to exit businesses conducted by the nonregulated subsidiaries Xcel Energy International and e prime. NRG, Xcel Energy International, e prime, Seren, Planergy International, Inc., UE and Quixx Corp. are presented as components of discontinued operations. See Note 2 to the Consolidated Financial Statements.

In 2004, Xcel Energy began consolidating the financial statements of subsidiaries in which it has a controlling financial interest, pursuant to the requirements of FASB Interpretation No. 46, as revised (FIN No. 46). Historically, consolidation has been required only for subsidiaries in which an enterprise has a majority voting interest. As a result, Xcel Energy is required to consolidate a portion of its affordable housing investments made through Eloigne, which for periods prior to 2004 are accounted for under the equity method. As of Dec. 31, 2005, the assets of the affordable housing investments consolidated as a result of FIN No. 46, as revised, were approximately $136 million and long-term liabilities were approximately $75 million, including long-term debt of $72 million. Investments of $51 million, previously reflected as a component of investments in unconsolidated affiliates, have been consolidated with the entities assets initially recorded at their carrying amounts as of

Jan. 1, 2004. The long-term debt is collateralized by the affordable housing projects and is nonrecourse to Xcel Energy.

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

Revenue Recognition Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

Xcel Energy s utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. In addition, Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees. A summary of significant rate-adjustment mechanisms follows:

NSP-Minnesota s rates include a cost-of-fuel-and-purchased-energy and a cost-of-gas recovery mechanism allowing dollar-for-dollar recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively.

NSP-Wisconsin s rates include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. In Wisconsin, requests can be made for recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

PSCo generally recovers all prudently incurred electric fuel and purchased energy costs through an electric-commodity adjustment clause. This fuel mechanism also has in place a sharing among customers and shareholders of certain fuel and energy costs, with an $11.25 million maximum on any cost sharing over or under an allowed electric-commodity adjustment formula rate, and a sharing among shareholders and customers of certain gains and losses on trading margins.

In Texas, SPS may request periodic adjustments to provide electric fuel and purchased energy cost recovery. In New Mexico, SPS has a monthly fuel and purchased power cost-recovery factor.

In Colorado, PSCo operates under an electric performance-based regulatory plan, which provides for an annual earnings test in which earnings above the authorized return on equity are refunded to customers. NSP-Minnesota and PSCo operate under various service standards in Minnesota and Colorado, respectively, which could require customer refunds if certain criteria are not met. NSP-Minnesota and PSCo s rates in Minnesota and Colorado, respectively, also include monthly adjustments for the recovery of conservation and energy-management program costs, which are reviewed annually.

NSP-Minnesota, NSP-Wisconsin, PSCo and SPS sell firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms.

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

Xcel Energy s commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Commodity trading activities are not associated with energy produced from Xcel Energy s generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value in accordance with SFAS No. 133, as amended. In addition, commodity trading results include the impact of any margin-sharing mechanisms.

Derivative Financial Instruments Xcel Energy and its subsidiaries utilize a variety of derivatives, including commodity forwards, futures and options, index or fixed price swaps and basis swaps, to mitigate market risk and to enhance its operations. For further discussion of Xcel Energy s risk management and derivative activities, see Note 12 to the

Consolidated Financial Statements.

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

Xcel Energy determines the depreciation of its plant by using the straight-line method, which spreads the original cost equally over the plant s useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.2 percent, 3.1 percent and 3.0 percent for the years ended Dec. 31, 2005, 2004 and 2003, respectively.

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

Decommissioning Xcel Energy accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. The fair value of external nuclear decommissioning fund investments are estimated based on quoted market prices for those or similar investments. Unrealized gains or losses are deferred as regulatory assets or liabilities. For more information on nuclear decommissioning, see Note 15 to the Consolidated Financial Statements.

PSCo also previously operated a nuclear generating plant, which has been decommissioned and was repowered using natural gas. PSCo s costs associated with decommissioning were deferred and amortized consistent with regulatory recovery. These costs were fully recovered through rates in July 2005.

Nuclear Fuel Expense Nuclear fuel expense, which is recorded as the nuclear generating plants use fuel, includes the cost of fuel used in the current period, as well as future disposal costs of spent nuclear fuel. In addition, nuclear fuel expense includes fees assessed by the DOE for NSP-Minnesota s portion of the cost of decommissioning the DOE s fuel-enrichment facility.

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

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

Legal Costs Litigation accruals are recorded when it is probable Xcel Energy is liable for the costs and the liability can be reasonably estimated. Legal accruals are recorded net of insurance recovery. Legal costs related to settlements are not accrued, but expensed as incurred.

Income Taxes Xcel Energy and its domestic subsidiaries file consolidated federal income tax returns. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries were included in some state returns, but not all, of these combined returns in 2003. NRG has not been consolidated or combined in any of Xcel Energy s income tax returns since 2003.

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

Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 16 to the Consolidated Financial Statements.

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

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

Inventory All inventory is recorded at average cost.

Regulatory Accounting Our regulated utility subsidiaries account for certain income and expense items in accordance with SFAS No. 71 Accounting for the Effects of Certain Types of Regulation. Under SFAS No. 71:

Certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and

Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 16 to the Consolidated Financial Statements.

Stock-Based Employee Compensation Xcel Energy has several stock-based compensation plans. Those plans are accounted for using the intrinsic-value method. Compensation expense is not recorded for stock options because there is no difference between the market price and the purchase price at grant date. Compensation expense is recorded for restricted stock and stock units awarded to certain employees, which are held until the restriction lapses or the stock is forfeited. For more information on stock compensation impacts, see Note 9 to the Consolidated Financial Statements.

Deferred Financing Costs Other assets also included deferred financing costs, net of amortization, of approximately $42 million and $44 million at Dec. 31, 2005 and 2004, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

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

Reclassifications Certain items in the statements of operations, balance sheets and the statements of cash flows have been reclassified from prior-period presentation to conform to the 2005 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily related to the presentation of UE as discontinued operations following the announcement of its sale in March 2005, as discussed later. In addition, fees collected from customers on behalf of governmental agencies were reclassified to be presented net of the related payments made to the agencies.

2. Discontinued Operations

Xcel Energy classified and accounted for certain assets as held for sale at Dec. 31, 2005 and 2004. Assets held for sale are valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, management considered cash flow analyses, bids and offers related to those assets and businesses. Assets held for sale are not depreciated.

Results of operations for divested businesses and the results of businesses held for sale are reported for all periods presented on a net basis as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale in 2005 and 2004 have been reclassified to assets and liabilities held for sale in the accompanying Balance Sheet.

Regulated Utility Segment

During January 2004, Xcel Energy reached an agreement to sell its regulated electric and natural gas subsidiary, Cheyenne. Black Hills Corp. purchased all the common stock of Cheyenne, including the assumption of outstanding debt of approximately $25 million, for approximately $90 million, plus a working capital adjustment finalized in 2005. The sale was completed on Jan. 21, 2005, and resulted in an after-tax loss of approximately $13 million, or 3 cents per share, which was accrued at Dec. 31, 2004.

During 2003, Xcel Energy completed the sale of two subsidiaries in its regulated natural gas utility segment: Viking and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded for the natural gas utility segment, primarily related to the sale of Viking.

NRG Segment

Change in Accounting for NRG in 2003 Prior to NRG s bankruptcy filing in May 2003, Xcel Energy accounted for NRG as a consolidated subsidiary. However, as a result of NRG s bankruptcy filing, Xcel Energy no longer had the ability to control the operations of NRG. Accordingly, effective as of the bankruptcy filing date, Xcel Energy ceased the consolidation of NRG and began accounting for its investment in NRG using the equity method in accordance with Accounting Principles Board Opinion No. 18 The Equity Method of Accounting for Investments in Common Stock. After changing to the equity method, Xcel Energy was limited in the amount of NRG s losses subsequent to the bankruptcy date that it was required to record. In accordance with these limitations under the equity method, Xcel Energy stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provided for loss recognition by Xcel Energy until its investment in NRG was written off to zero, with further loss recognition to continue if its financial commitments to NRG existed beyond amounts already invested.

Prior to NRG entering bankruptcy, Xcel Energy recorded more losses than the limitations provided for as of June 30, 2003. Upon Xcel Energy s divestiture of its interest in NRG in December 2003, the NRG losses recorded in excess of Xcel Energy s investment in and financial commitment to NRG were reversed. This resulted in an adjustment of the total NRG losses recorded for the year 2003 to $251 million. Xcel Energy s share of NRG s results for all 2003 periods is reported in a single line item, Equity in Losses of NRG, as a component of discontinued operations. NRG s 2003 results do reflect some effects of asset impairments, as discussed below.

NRG Asset Impairments In 2002, NRG experienced credit-rating downgrades, defaults under numerous credit agreements, increased collateral requirements and reduced liquidity. These events resulted in impairment reviews of a number of NRG assets. NRG completed an analysis of the recoverability of the asset-carrying values of its projects each period, factoring in the probability weighting of different courses of action available to NRG, given its financial position and liquidity constraints at the time of each analysis. This approach was applied consistently to asset groups with similar uncertainties and cash flow streams. As a result, NRG determined that many of its construction projects and its operational projects became impaired during 2002 and 2003 and required being written down to fair market value. In applying those provisions, NRG management considered cash flow analyses, bids and offers related to those projects.

Nonregulated Subsidiaries All Other Segment

Utility Engineering In March 2005, Xcel Energy agreed to sell its nonregulated subsidiary Utility Engineering Corp. (UE), to Zachry Group, Inc. In April 2005, Zachry acquired all of the outstanding shares of UE. Xcel Energy recorded an insignificant loss in the first quarter of 2005 as a result of the transaction. In August 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of Quixx Corp., a former subsidiary of UE that partners in cogeneration projects, and was not included in the sale of UE to Zachry.

Seren On Sept. 27, 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren Innovations, Inc., a wholly owned broadband subsidiary.

On May 25, 2005, Xcel Energy reached an agreement to sell Seren s California assets to WaveDivision Holdings, LLC, which was completed in November 2005. In July 2005, Xcel Energy reached an agreement to sell Seren s Minnesota assets to Charter Communications, which was completed in January 2006. An estimated after-tax impairment charge, including disposition costs, of $143 million, or 34 cents per share, was recorded in 2004. Based on the sales agreements entered into in 2005, the estimate was adjusted in 2005 to reflect a total asset impairment of $140 million.

Xcel Energy International and e prime In December 2003, the board of directors of Xcel Energy approved management s plan to exit the businesses conducted by its nonregulated subsidiaries Xcel Energy International and e prime. The exit of all business conducted by e prime was completed in 2004.

Results of discontinued nonregulated operations in 2004 include the impact of the sale of the Argentina subsidiaries of Xcel Energy International. The sales took place in a series of three transactions, with a total sales price of approximately $31 million. In addition to the sales price, Xcel Energy also received approximately $21 million at the closing of one transaction as redemption of its capital investment. The sales resulted in a gain of approximately $8 million, including the realization of approximately $7 million of income tax benefits realizable upon the sale of the Xcel Energy International assets.

Results of discontinued nonregulated operations in 2003, other than NRG, include an after-tax loss expected on the disposal of all Xcel Energy International assets of $59 million, based on the estimated fair value of such assets. The fair value represents a market bid or appraisal received that is believed to best reflect the assets fair value at Dec. 31, 2003. Xcel Energy s remaining investment in Xcel Energy International at Dec. 31, 2003, was approximately $39 million. Losses from discontinued nonregulated operations in 2003 also include a charge of $16 million for costs of settling a Commodity Futures Trading Commission trading investigation of e prime.

Tax Benefits Related to Investment in NRG With NRG s emergence from bankruptcy in December 2003, Xcel Energy divested its ownership interest in NRG. Xcel Energy has recognized tax benefits related to the divestiture. These tax benefits, since related to Xcel Energy s investment in discontinued NRG operations, also are reported as discontinued operations.

During 2002, Xcel Energy recognized an initial estimate of the expected tax benefits of $706 million. Based on the results of a 2003 preliminary tax basis study of NRG, Xcel Energy recorded $404 million of additional tax benefits in 2003. In 2004, the NRG basis study was updated and previously recognized tax benefits were reduced by $13 million. In 2005, a $17 million tax benefit was recorded to reflect the final federal income tax resolution of Xcel Energy s divested interest in NRG.

Summarized Financial Results of Discontinued Operations

(Thousands of Dollars)	Utility Segment	NRG Segment	All Other Segment	Total
2005				
Operating revenue	$ 6,579	$	$ 63,206	$ 69,785
Operating and other expenses	6,131		68,669	74,800
Special charges and impairments				
Pretax income (loss) from operations of discontinued components	448		(5,463)	(5,015)
Income tax expense (benefit)	268		(19,217)	(18,949)
Income from operations of discontinued components	180		13,754	13,934
Estimated pretax gain on disposal of discontinued components				
Income tax benefit				
Gain on disposal of discontinued components				
Net income from discontinued operations	$ 180	$	$ 13,754	$ 13,934
2004				
Operating revenue	$ 72,232	$	$ 179,890	$ 252,122
Operating and other expenses	68,305		194,605	262,910
Special charges and impairments	6,574		228,439	235,013
Pretax loss from operations of discontinued components	(2,647)		(243,154)	(245,801)
Income tax expense (benefit)	6,388		(78,021)	(71,633)
Loss from operations of discontinued components	(9,035)		(165,133)	(174,168)
Estimated pretax gain on disposal of discontinued components			961	961
Income tax benefit			6,904	6,904
Gain on disposal of discontinued components			7,865	7,865
Net loss from discontinued operations	$ (9,035)	$	$ (157,268)	$ (166,303)
2003				
Operating revenue	$ 51,723	$	$ 298,550	$ 350,273
Operating and other expenses	46,539		330,538	377,077
Special charges and impairments (including net disposal losses)		(1,664)	58,700	57,036
Equity in NRG losses		253,043		253,043
Pretax income (loss) from operations of discontinued components	5,184	(251,379)	(90,688)	(336,883)
Income tax expense (benefit)	1,667		(414,826)	(413,159)
Income (loss) from operations of discontinued components	3,517	(251,379)	324,138	76,276
Estimated pretax gain on disposal of discontinued components	40,072			40,072
Income tax expense	16,780			16,780
Gain on disposal of discontinued components	23,292			23,292
Net income (loss) from discontinued operations	$ 26,809	$ (251,379)	$ 324,138	$ 99,568

The major classes of assets and liabilities held for sale and related to discontinued operations as of Dec. 31 are as follows:

(Thousands of Dollars)	2005	2004
Cash	$ 12,658	$ 33,228
Restricted cash		15,000
Trade receivables net	6,101	24,364
Deferred income tax benefits	157,812	234,305
Other current assets	24,240	60,351
Current assets	200,811	367,248
Property, plant and equipment net	29,845	155,428
Deferred income tax benefits	352,171	338,863
Other noncurrent assets	19,269	46,293
Noncurrent assets	401,285	540,584
Accounts payable trade	7,657	29,451
Other current liabilities	36,000	83,480
Current liabilities	43,657	112,931
Long-term debt		24,800
Other noncurrent liabilities	6,936	64,442
Noncurrent liabilities	$ 6,936	$ 89,242

3. Short-Term Borrowings

Notes Payable and Commercial Paper During 2005, Xcel Energy, PSCo and SPS resumed short-term borrowings in the commercial paper market. Information regarding notes payable and commercial paper for the years ended Dec. 31, 2005 and 2004, is presented in the following table:

(Millions of Dollars, except interest rates)	2005	2004
Notes payable to banks	$	$ 312.3
Commercial paper	746.1	
Total short-term debt	$ 746.1	$ 312.3
Weighted average interest rate at year-end	4.46%	4.15%

Credit Facilities On Dec. 1, 2005, PSCo entered into an agreement with Wells Fargo Bank, N.A. to provide PSCo a committed five-month, $50 million seasonal revolving credit facility. The interest rate is based on either Wells Fargo Bank s prime rate or the applicable LIBOR, plus a borrowing margin as determined by PSCo s credit worthiness. PSCo entered into this agreement to ensure adequate liquidity for rising natural gas prices during the winter months. As of Dec. 31, 2005, PSCo had not borrowed against this facility.

In addition, on Dec. 12, 2005, PSCo entered into a $25 million good-until-canceled uncommitted credit line with KBC Bank to provide additional short-term seasonal liquidity as a result of higher natural gas prices. As of Dec. 31, 2005, PSCo had not utilized this credit line.

4. Long-Term Debt

Credit Facilities At Dec. 31, 2005, Xcel Energy and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility	Available *	Term	Maturity
NSP-Minnesota	$ 450	$ 190.3	Five year	April 2010
PSCo	$ 600	$ 258.9	Five year	April 2010
SPS	$ 250	$ 164.4	Five year	April 2010
Xcel Energy holding company	$ 700	$ 356.0	Five year	November 2009
Total	$ 2,000	$ 969.6		

* Net of credit facility borrowings, issued and outstanding letters of credit and commercial paper borrowings

98

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. Each credit facility has one financial covenant requiring that the debt-to-total-capitalization ratio of each entity be less than or equal to 65 percent with which all were in compliance. The interest rates under these lines of credit are based on either the agent bank s prime rate or the applicable London Interbank Offered Rate (LIBOR), plus a borrowing margin as determined by each entity s credit worthiness.

Xcel Energy has a $700 million, five-year senior unsecured revolving credit facility that matures in November 2009. Xcel Energy has the right to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval. As of Dec. 31, 2005, Xcel Energy had no direct borrowings on this line of credit, however the credit facility was used to provide backup for $325.5 million of commercial paper outstanding and $18.5 million of letters of credit. As discussed in Note 13 to the Consolidated Financial Statements, $35.2 million of letters of credit were outstanding at Dec. 31, 2005, of which $18.5 million were supported by the Xcel Energy credit facility and are included in the above table.

Xcel Energy s 2007 and 2008 series convertible senior notes are convertible into shares of Xcel Energy common stock at a conversion price of $12.33 per share. Conversion is at the option of the holder at any time prior to maturity. In addition, Xcel Energy must make additional payments of interest, referred to as protection payments, on the notes in an amount equal to any portion of regular quarterly per share dividends on common stock that exceeds $0.1875 that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. On May 25, 2005, the board of directors of Xcel Energy voted to raise the quarterly dividend on its common stock from $0.2075 to $0.2150. Consequently, as of Dec. 31, 2005, a total of $2.4 million in additional interest expense has been recorded.

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

Maturities of long-term debt are:

2006	$	835.5 million
2007	$	338.9 million
2008	$	632.4 million
2009	$	557.8 million
2010	$	1,031.6 million

5. Preferred Stock

Xcel Energy has authorized 7,000,000 shares of preferred stock with a $100 par value. At Dec. 31, 2005, Xcel Energy had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends. Under the PUHCA, unless there was an order from the SEC, a holding company or any subsidiary could declare and pay dividends only out of retained earnings. With the repeal of the PUHCA, restrictions on the ability of holding companies or utility subsidiaries to declare dividends set out in that statute no longer apply.

The holders of the $3.60 series preferred stock are entitled to three votes per each share held. The holders of the other series of preferred stock are entitled to one vote per share. In the event dividends payable on the preferred stock of any series outstanding is in arrears in an amount equal to four quarterly dividends, the holders of preferred stocks, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the board of directors. The holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of Xcel Energy s subsidiaries also authorize the issuance of preferred stock. However, at Dec. 31, 2005, there are no preferred shares outstanding.

	Preferred Shares Authorized	Par Value	Preferred Shares Outstanding
SPS	10,000,000	$ 1.00	None
PSCo	10,000,000	$ 0.01	None

6. Mandatorily Redeemable Preferred Securities of Subsidiary Trusts

NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, had $200 million of 7.875-percent

99

trust preferred securities issued and outstanding that were originally scheduled to mature in 2037. The preferred securities were redeemable at NSP Financing I s option at $25 per share, beginning in 2002. On July 31, 2003, NSP-Minnesota redeemed the $200 million of trust preferred securities. A certificate of cancellation was filed to dissolve NSP Financing I on Sept. 15, 2003.

PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, had $194 million of 7.60-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2038. The securities were redeemable at the option of PSCo after May 2003, at 100 percent of the principal amount outstanding plus accrued interest. On June 30, 2003, PSCo redeemed the $194 million of trust preferred securities. A certificate of cancellation was filed to dissolve PSCo Capital Trust I on Dec. 29, 2003.

Southwestern Public Service Capital I, a wholly owned, special-purpose subsidiary trust of SPS, had $100 million of 7.85-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2036. The securities were redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. On Oct. 15, 2003, SPS redeemed the $100 million of trust preferred securities. A certificate of cancellation was filed to dissolve SPS Capital I on Jan. 5, 2004.

Distributions paid to preferred security holders were reflected as a financing cost in the Consolidated Statements of Operations, along with interest charges.

7. Generating Plant Ownership and Operation

Joint Plant Ownership Following are the investments by Xcel Energy s subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2005:

(Thousands of Dollars)		Plant in Service		Accumulated Depreciation		Construction Work in Progress	Ownership%
NSP-Minnesota							
Sherco Unit 3	$	500,266	$	282,145	$	665	59.0
Sherco Common Facilities Units 1, 2 and 3		102,988		53,552		1,196	65.6
Transmission facilities, including substations		4,832		1,878			59.0
Total NSP-Minnesota	$	608,086	$	337,575	$	1,861	
PSCo							
Hayden Unit 1	$	84,357	$	43,579	$	635	75.5
Hayden Unit 2		80,034		45,637		1,006	37.4
Hayden Common Facilities		28,244		5,538			53.1
Craig Units 1 and 2		52,848		26,318		24	9.7
Craig Common Facilities Units 1, 2 and 3		32,384		9,673			6.5-9.7
Comanche Unit 3						54,960	74.7
Transmission and other facilities, including substations		114,788		42,412		13	11.6-68.1
Total PSCo	$	392,655	$	173,157	$	56,638	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota s share of operating expenses and construction expenditures are included in the applicable utility accounts. PSCo s current operational assets include approximately 320 megawatts of jointly owned generating capacity. PSCo s share of operating expenses and construction expenditures are included in the applicable utility accounts. PSCo began major construction on a new jointly owned 750-megawatt, coal-fired unit in Pueblo, Colo. in January 2006. Major construction on the new unit, Comanche 3, is expected to be completed in 2010. PSCo is the operating agent under the joint ownership agreement. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

Nuclear Plant Operation The Nuclear Management Company (NMC) is an operating company that manages the operations, maintenance and physical security of several nuclear generating units on five sites, including three units / two sites owned by NSP-Minnesota. NSP-Minnesota continues to own the plants, controls all energy produced by the plants and retains responsibility for nuclear property and liability insurance and decommissioning costs. The Wisconsin Public Service Corporation is no longer participating in NMC after the sale of its Kewaunee nuclear power plant in July 2005. In January 2006, Florida Power & Light purchased the majority interest in the Duane Arnold plant from Alliant Energy and announced it will assume management of the plant. As a result, NSP-Minnesota s ownership interest in NMC has increased to 25 percent. In accordance with the Nuclear Power

Plant Operating Services Agreement, NSP-Minnesota also pays its proportionate share of the operating expenses and capital improvement costs incurred by NMC. NSP-Minnesota paid NMC $257.1 million in 2005, $314.7 million in 2004 and $227.0 million in 2003.

8. Income Taxes

Xcel Energy s federal net operating loss and tax credit carry forwards are estimated to be $1.4 billion and $107.6 million, respectively. A portion of the net operating loss in the amount of $1.1 billion and a portion of the tax credit carry forward in the amount of $28.8 million are accounted for in discontinued operations. The carry forward periods expire in 2023 and 2024. Xcel Energy also has net operating loss and tax credit carry forwards in some states. The state carry forward periods expire between 2014 and 2024. A valuation allowance was recorded against deferred tax assets for capital loss carry forwards related to discontinued operations. The valuation allowance was $44 million as of Dec. 31, 2005, and $46 million as of Dec. 31, 2004. The net reduction in valuation allowance of $2 million was due to capital gains. The capital loss carry forward period expires in 2009.

Total income tax expense from continuing operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following is a table reconciling such differences for the years ending Dec. 31:

	2005	2004	2003
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	2.5	3.3	2.3
Life insurance policies	(4.6)	(4.0)	(3.8)
Tax credits recognized	(4.4)	(4.4)	(3.9)
Regulatory differences utility plant items	(0.3)	(0.1)	0.8
Resolution of income tax audits and prior-period adjustments	(0.3)	(5.3)	(5.1)
Other net	(2.1)	(0.8)	(0.7)
Effective income tax rate from continuing operations	25.8%	23.7%	24.6%

Income taxes comprise the following expense (benefit) items for the years ending Dec. 31:

(Thousands of Dollars)	2005	2004	2003
Current federal tax expense	$ (4,122)	$ 88,514	$ 111,986
Current state tax expense (benefit)	(15,733)	32,135	(592)
Current tax credits	(45)	(3,798)	(3,137)
Deferred federal tax expense	191,900	67,716	83,245
Deferred state tax expense	31,235	3,574	3,298
Deferred tax credits	(18,077)	(14,017)	(11,668)
Deferred investment tax credits	(11,619)	(12,189)	(12,440)
Total income tax expense from continuing operations	$ 173,539	$ 161,935	$ 170,692

The components of Xcel Energy s net deferred tax liability from continuing operations (current and noncurrent portions) at Dec. 31 were:

(Thousands of Dollars)		2005		2004
Deferred tax liabilities:				
Differences between book and tax bases of property	$	2,245,748	$	2,056,951
Regulatory assets		257,843		244,388
Employee benefits		25,711		33,191
Partnership income/loss		10,010		10,310
Service contracts		8,539		11,369
Other		85,810		31,227
Total deferred tax liabilities	$	2,633,661	$	2,387,436
Deferred tax assets:				
Net operating loss carry forward	$	119,124	$	88,159
Other comprehensive income		80,356		63,469
Deferred investment tax credits		51,286		55,967
Tax credit carry forward		86,143		51,046
Regulatory liabilities		40,835		39,415
Book reserves and other		46,106		70,892
Total deferred tax assets	$	423,850	$	368,948
Net deferred tax liability	$	2,209,811	$	2,018,488

9. Common Stock and Stock-Based Compensation

Common Stock and Equivalents Xcel Energy has common stock equivalents consisting of convertible senior notes, restricted stock units and stock options, as discussed later.

In 2005, 2004 and 2003, Xcel Energy has 13.3 million, 14.3 million and 15.6 million options outstanding, respectively that were antidilutive and therefore excluded from the earnings per share calculation. The dilutive impact of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

(Shares and dollars in thousands, except per share amounts)	2005 Income	Shares	Per Share Amount	2004 Income	Shares	Per Share Amount	2003 Income	Shares	Per Share Amount
Income from continuing operations	$ 499,038			$ 522,264			$ 522,824		
Less: Dividend requirements on preferred stock	(4,241)			(4,241)			(4,241)		
Basic earnings per share									
Income from continuing operations	494,797	402,330	$ 1.23	518,023	399,456	$ 1.30	518,583	398,765	$ 1.30
Effect of dilutive securities:									
	11,498	18,654		11,940	18,654		11,213	18,654	

$ 230 million convertible debt									
$ 57.5 million convertible debt	2,875	4,663		2,985	4,663		311	507	
Convertible debt option								508	
Restricted stock units					544			464	
Options		24			17			14	
Diluted earnings per share									
Income from continuing operations and assumed conversions	$ 509,170	425,671	$ 1.20	$ 532,948	423,334	$ 1.26	$ 530,107	418,912	$ 1.26

Stock-Based Compensation Xcel Energy has incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate Xcel Energy s earnings per share include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables below include awards made by Xcel Energy and some of its predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

Activity in stock options was as follows for the years ended Dec. 31:

	2005		2004		2003	
(Awards in thousands)	Awards	Average Price	Awards	Average Price	Awards	Average Price
Outstanding beginning of year	14,606	$ 26.67	15,614	$ 26.49	16,981	$ 26.29
Exercised	(152)	$ 17.30	(45)	$ 15.08	(190)	$ 12.21
Forfeited	(213)	$ 26.84	(172)	$ 25.10	(580)	$ 28.48
Expired	(665)	$ 23.71	(791)	$ 24.08	(597)	$ 23.41
Outstanding at end of year	13,576	$ 26.92	14,606	$ 26.67	15,614	$ 26.49
Exercisable at end of year	13,529	$ 26.91	10,096	$ 26.58	9,358	$ 25.59

	Range of Exercise Prices		
	$ 13.81 to $25.50	$ 25.51 to $27.00	$ 27.01 to $51.25
Options outstanding:			
Number outstanding	2,613,302	7,001,694	3,960,810
Weighted average remaining contractual life (years)	2.9	4.4	4.4
Weighted average exercise price	$ 20.44	$ 26.28	$ 32.31
Options exercisable:			
Number exercisable	2,613,302	7,001,694	3,913,810
Weighted average exercise price	$ 20.44	$ 26.28	$ 32.33

Certain employees also may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock vests in equal annual installments over a three-year period from the date of grant. Xcel Energy reinvests dividends on the restricted stock it holds while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. Restricted stock has a value equal to the market-trading price of Xcel Energy s stock at the grant date. Xcel Energy granted 28,626 shares of restricted stock in 2005 when the grant-date market price was $17.81. Xcel Energy granted 65,090 shares of restricted stock in 2004 when the grant-date market price was $17.40. Xcel Energy did not grant any shares of restricted stock in 2003. Compensation expense related to these awards was not significant.

On March 28, 2003, the governance, compensation and nominating committee of Xcel Energy s board of directors granted restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan approved by the shareholders in 2000. Restrictions on the restricted stock units lapse upon the achievement of a 27-percent total shareholder return (TSR) for 10 consecutive business days and other criteria relating to Xcel Energy s common equity ratio. Under no circumstances will the restrictions lapse until one year after the grant date. TSR is measured using the market price per share of Xcel Energy common stock, which at the grant date was $12.93, plus common dividends declared after grant date. The TSR was met in the fourth quarter of 2003, and approximately $31 million of compensation expense was recorded at Dec. 31, 2003. The remaining cost of $10 million related to the 2003 restricted stock units was recorded in the first quarter of 2004. In January 2004, Xcel Energy s board of directors approved the repurchase of up to 2.5 million shares of common stock to fulfill the requirements of the restricted stock unit exercise. On March 29, 2004, the restricted stock units lapsed, and Xcel Energy issued approximately 1.6 million shares of common stock.

The performance share award is entirely dependent on a single measure, the TSR. Xcel Energy s TSR will be measured over a three-year period. Xcel Energy s TSR is compared to the TSR of other companies in the Edison Electric Institute s Electrics Index. At the end of the three-year period, potential payouts of the performance shares range from 0 percent to 200 percent, depending on Xcel Energy s TSR compared to the peer group.

On Dec. 9, 2003, the governance, compensation and nominating committee of Xcel Energy s board of directors approved restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan. On Jan. 2, 2004, Xcel Energy granted 836,186 restricted stock units and performance shares. The grant-date market price used to calculate the TSR for this grant is $17.03.

On Dec. 14, 2004, the governance, compensation and nominating committee of Xcel Energy s board of directors granted restricted stock units under the Xcel Energy Inc. Omnibus Incentive Plan. Payout of the units and the lapsing of restrictions on the transfer of units are based on two separate performance criteria. A portion of the awarded units plus associated earned dividend equivalents will be settled, and the restricted period will lapse after Xcel Energy achieves a specified earnings per share growth (adjusted for corporate-owned life insurance) measured against year-end earnings per share (adjusted for corporate-owned life insurance). Additionally, Xcel Energy s annual dividend paid on its common stock must remain at $0.83 per share or greater. Earnings per share growth will be measured annually at the end of each fiscal year. However, in no event will the restrictions lapse prior to two years after the date of grant. The remaining awarded units plus associated earned dividend equivalents will be settled, and the restricted period will lapse after the average of actual performance results (adjusted for actual megawatt hours) for the three components of an environmental index measured as a percentage of target performance meets or exceeds 100 percent. The environmental index will be measured annually at the end of each fiscal year. However, in no event will the restrictions lapse prior to two years after the date of grant. If the performance criteria have not been met within four years of the date of grant, all associated units shall be forfeited. On Jan. 1, 2005, Xcel Energy granted 519,362 restricted stock units.

On Dec. 14, 2004, the governance, compensation and nominating committee of Xcel Energy s board of directors approved performance shares under the Xcel Energy Inc. Omnibus Incentive Plan. On Jan. 1, 2005, Xcel Energy granted 323,889 performance shares.

On Dec. 13, 2005, the governance, compensation and nominating committee of Xcel Energy s board of directors approved restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan. On Jan. 1, 2006, Xcel Energy granted approximately 653,000 restricted stock units and performance shares.

Compensation expense related to restricted stock units and performance shares of approximately $14.9 million, $16.8 million and $35.0 million was recorded in 2005, 2004 and 2003, respectively.

Xcel Energy applies Accounting Principles Board Opinion No. 25 Accounting for Stock Issued to Employees in accounting for stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options, as the exercise price of the options equals the fair-market value of Xcel Energy s common stock at the date of grant. In December 2002, the FASB issued SFAS No. 148 Accounting for Stock-Based Compensation Transition and Disclosure, amending SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation, and requiring disclosure in both annual and interim Consolidated Financial Statements about the method used and the effect of the method used on results. The pro forma impact of applying SFAS No. 148 is as follows at Dec. 31:

(Thousands of Dollars, except per share amounts)	**2005**	**2004**	**2003**
Net income as reported	$ 512,972	$ 355,961	$ 622,392
Less: Total stock-based employee compensation expense determined under fair-value-based method for stock options, net of related tax effects	(1,180)	(2,339)	(3,897)
Pro forma net income (loss)	$ 511,792	$ 353,622	$ 618,495
Earnings per share:			
Basic as reported	$ 1.26	$ 0.88	$ 1.55
Basic pro forma	$ 1.26	$ 0.87	$ 1.54
Diluted as reported	$ 1.23	$ 0.87	$ 1.50
Diluted pro forma	$ 1.23	$ 0.86	$ 1.49

Common Stock Dividends Per Share Historically, Xcel Energy has paid quarterly dividends to its shareholders. Dividends on common stock are paid as declared by the board of directors. Dividends paid per share for the quarters of 2005, 2004 and 2003 are:

2005		**Dividends Per Share**
First Quarter	$	0.2075
Second Quarter		0.2150
Third Quarter		0.2150
Fourth Quarter		0.2150
	$	0.8525

2004		
First Quarter	$	0.1875
Second Quarter		0.2075
Third Quarter		0.2075
Fourth Quarter		0.2075
	$	**0.8100**

2003		
First Quarter	$	0.1875
Second Quarter		0.1875
Third Quarter		0.1875
Fourth Quarter		0.1875
	$	**0.7500**

Dividend and Other Capital-Related Restrictions Formerly, under PUHCA, unless there was an order from the SEC, a holding company or any subsidiary could declare and pay dividends only out of retained earnings. In May 2003, Xcel Energy received authorization from the SEC to pay an aggregate amount of $152 million of common and preferred dividends out of capital and unearned surplus. Xcel Energy used this authorization to declare and pay approximately $150 million for its first- and second-quarter dividends in 2003. At Dec. 31, 2005, Xcel Energy s retained earnings were approximately $562.1 million. With the repeal of the PUHCA, restrictions on the ability of holding companies or utility subsidiaries to declare dividends set out in that statute will no longer apply. However, utility dividends will be subject to the FERC s jurisdiction under the Federal Power Act, which prohibits the payment of utility dividends out of capital accounts.

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 and not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, the capitalization ratio at Dec. 31, 2005, was 84 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy s ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of Xcel Energy common stock.

In addition, NSP-Minnesota s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $854 million in additional cash dividends on common stock at Dec. 31, 2005.

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, were limited, under the PUHCA, in their ability to issue securities. Such registered holding companies and their subsidiaries could not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy did not qualify for any of the main exemptive rules, it sought and received financing authority from the SEC under the PUHCA for various financing arrangements. Xcel Energy s current financing authority permits it, subject to certain conditions, to issue through June 30, 2008, up to $1.8 billion of new long-term debt, common equity and equity-linked securities and $1.0 billion of short-term debt securities during the new authorization period, provided that the aggregate amount of long-term debt, common equity, and equity-linked and short-term debt securities issued during the new authorization period does not exceed $2.0 billion.

Xcel Energy s ability to issue securities under the financing authority was subject to a number of conditions. One of the conditions of the financing authority was that Xcel Energy s ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. As of Dec. 31, 2005, such common equity ratio was approximately 42 percent. Additional conditions require that a security to be issued that is rated, must be at least rated investment grade by one nationally recognized rating agency. Finally, all outstanding securities that are rated must be rated investment grade by at least one nationally recognized rating agency. On Feb. 10, 2006, Xcel Energy s senior unsecured debt was considered investment grade by Standard & Poor s, Moody s and Fitch.

Upon the repeal of the PUHCA, these limitations on Xcel Energy s financings generally will no longer apply, nor will the PUHCA restrictions generally apply to the financings by the utility subsidiaries. However, utility financings and intra-system financings will become subject to the jurisdiction of the FERC under the Federal Power Act. The FERC by rule has granted a blanket authorization under certain intra-system financings involving holding companies. Requests to the FERC to clarify its rules or grant similar blanket authorizations filed by other entities are presently pending before the FERC. Xcel Energy and the utility subsidiaries are presently evaluating the specific applications that they will need to file with the FERC due to the repeal of the PUHCA. It is possible that in lieu of requesting authority from the FERC for intra-system financings, Xcel Energy and the utility subsidiaries may rely in the interim on a transitional savings clause that would permit such financing transactions to the extent authorized by the SEC financing order and so long as the conditions in the SEC financing order continue to be satisfied.

Stockholder Protection Rights Agreement In June 2001, Xcel Energy adopted a Stockholder Protection Rights Agreement. Each share of Xcel Energy s common stock includes one shareholder protection right. Under the agreement s principal provision, if any person or group acquires 15 percent or more of Xcel Energy s outstanding common stock, all other shareholders of Xcel Energy would be entitled to buy, for the exercise price of $95 per right, common stock of Xcel Energy having a market value equal to twice the exercise price, thereby substantially diluting the acquiring person s or group s investment. The rights may cause substantial dilution to a person or group that acquires 15 percent or more of Xcel Energy s common stock. The rights should not interfere with a transaction that is in the best interests of Xcel Energy and its shareholders because the rights can be redeemed prior to a triggering event for $0.01 per right.

10. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees. Approximately 56 percent of benefiting employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2005, NSP-Minnesota had 2,144 and NSP-Wisconsin had 417 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2007. PSCo had 2,165 bargaining employees covered under a collective-bargaining agreement, which expires in May 2006. SPS had 733 bargaining employees covered under a collective-bargaining agreement, which expires in October 2008.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee s average pay and Social Security benefits.

Xcel Energy s policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

Pension Plan Assets Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. In 2004, Xcel Energy completed a review of its pension plan asset allocation and adopted revised asset allocation targets. The target range for our pension asset allocation is 60 percent in equity investments, 20 percent in fixed income investments and 20 percent in nontraditional investments, such as real estate, timber ventures, private equity and a diversified commodities index.

The actual composition of pension plan assets at Dec. 31 was:

	2005	2004
Equity securities	65%	69%
Debt securities	20	19
Real estate	4	4
Cash	1	1
Nontraditional investments	10	7
	100%	100%

Xcel Energy bases its investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 12.0 percent, which is greater than the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long term. The Xcel Energy portfolio is heavily weighted toward equity securities and includes nontraditional investments that can provide a higher-than-average return. As is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels achieved by pension assets in any year. Investment returns in 2005,2004 and 2003 exceeded the assumed level of 8.75, 9.0 and 9.25 percent, respectively. Xcel Energy continually reviews its pension assumptions. In 2006, Xcel Energy will continue to use an investment-return assumption of 8.75 percent.

Benefit Obligations A comparison of the actuarially computed pension-benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	**2005**	**2004**
Accumulated Benefit Obligation at Dec. 31	$ 2,642,177	$ 2,575,317
Change in Projected Benefit Obligation		
Obligation at Jan. 1	$ 2,732,263	$ 2,632,491
Service cost	60,461	58,150
Interest cost	160,985	165,361
Plan amendments	300	
Actuarial loss	85,558	133,552
Settlements		(27,627)
Benefit payments	(242,787)	(229,664)
Obligation at Dec. 31	$ 2,796,780	$ 2,732,263
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 3,062,016	$ 3,024,661
Actual return on plan assets	254,307	284,600
Employer contributions	20,000	10,046
Settlements		(27,627)
Benefit payments	(242,787)	(229,664)
Fair value of plan assets at Dec. 31	$ 3,093,536	$ 3,062,016
Funded Status of Plans at Dec. 31		
Net asset	$ 296,756	$ 329,753
Unrecognized prior service cost	214,702	244,437
Unrecognized loss	281,519	176,957
Net pension amounts recognized on Consolidated Balance Sheets	$ 792,977	$ 751,147
Prepaid pension asset recorded (a)	$ 683,649	$ 642,873
Intangible asset recorded prior service costs	3,563	4,689
Minimum pension liability recorded	(88,280)	(63,967)
Accumulated other comprehensive income recorded pretax	198,542	170,554
Accumulated other comprehensive income recorded net of tax	123,279	106,007
Measurement Date	Dec. 31, 2005	Dec. 31, 2004
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	5.75%	6.00%
Expected average long-term increase in compensation level	3.50%	3.50%

(a) $22.1 million of the 2005 prepaid pension asset and $23.9 million of the 2004 prepaid pension asset relates to Xcel Energy s remaining obligation for companies that are now classified as discontinued operations.

During 2002, one of Xcel Energy s pension plans became underfunded, and at Dec. 31, 2005, had projected benefit obligations of $739.5 million, which exceeded plan assets of $609.8 million. All other Xcel Energy plans in the aggregate had plan assets of $2.5 billion and projected benefit obligations of $2.1 billion on Dec. 31, 2005. A minimum pension liability of $88.3 million was recorded related to the underfunded plan as of that date. A corresponding reduction in Accumulated Other Comprehensive Income, a component of Stockholders Equity, also was recorded, as previously recorded prepaid pension assets were reduced to record the minimum liability. Net of the related deferred income tax effects of the adjustments, total Stockholders Equity was reduced by $123.3 million at Dec. 31, 2005, due to the minimum pension liability for the underfunded plan.

Cash Flows Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in the years 2003 through 2005 for Xcel Energy s pension plans, and are not expected to require cash funding in 2006. PSCo elected to make voluntary contributions to its pension plan for bargaining employees of $9 million in 2004 and $14.7 million in 2005, Cheyenne voluntarily contributed $0.9 million to its pension plan for bargaining employees in 2004 and $0.3 million in 2005 and Xcel Energy voluntarily contributed $5.0 million to the NCE non-bargaining plan in 2005. PSCo expects to voluntarily contribute between $15 million and $30 million during 2006 to the pension plan for bargaining employees.

Benefit Costs The components of net periodic pension cost (credit) are:

(Thousands of Dollars)	2005	2004	2003
Service cost	$ 60,461	$ 58,150	$ 67,449
Interest cost	160,985	165,361	170,731
Expected return on plan assets	(280,064)	(302,958)	(322,011)
Curtailment gain			(17,363)
Settlement gain		(926)	(1,135)
Amortization of transition asset		(7)	(1,996)
Amortization of prior service cost	30,035	30,009	28,230
Amortization of net (gain) loss	6,819	(15,207)	(44,825)
Net periodic pension cost (credit) under SFAS No. 87 (a)	(21,764)	(65,578)	(120,920)
Credits not recognized due to effects of regulation	19,368	38,967	51,311
Net benefit credit recognized for financial reporting	$ (2,396)	$ (26,611)	$ (69,609)
Significant Assumptions Used to Measure Costs			
Discount rate	6.00%	6.25%	6.75%
Expected average long-term increase in compensation level	3.50%	3.50%	4.00%
Expected average long-term rate of return on assets	8.75%	9.00%	9.25%

(a) Includes pension credits related to discontinued operations of $1.3 million for 2005, $4.7 million for 2004 and $19.0 million for 2003. The 2003 credit is largely due to a $20.0 million curtailment gain related to termination of NRG employees as a result of the divestiture of NRG in December 2003.

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2006 pension cost calculations will be 8.75 percent. The cost calculation uses a market-related valuation of pension assets, which reduces year-to-year volatility by recognizing the differences between assumed and actual investment returns over a five-year period.

Xcel Energy also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy s operating cash flows.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $19.6 million in 2005, $21.9 million in 2004 and $15.9 million in 2003.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. Xcel Energy discontinued contributing toward health care benefits for former New Century Energies, Inc. (NCE) nonbargaining employees retiring after June 30, 2003. Employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Nonbargaining employees of the former NSP who retired after 1998, bargaining employees of the former NSP who retired after 1999 and nonbargaining employees of the former NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106 Employers Accounting for Postretirement Benefits Other Than Pension, Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy s retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. The Colorado jurisdictional SFAS No. 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS No. 106 costs, with regulatory differences fully amortized prior to 1997.

Plan Assets Certain state agencies that regulate Xcel Energy s utility subsidiaries also have issued guidelines related to the funding of SFAS No. 106 costs. SPS is required to fund SFAS No. 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo is required to fund SFAS No. 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. In 2004, the investment strategy for the union asset fund was changed to increase the investment mix in equity funds. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The actual composition of postretirement benefit plan assets at Dec. 31 was:

	2005	**2004**
Equity and equity mutual fund securities	61%	54%
Fixed income/debt securities	17	21
Cash equivalents	21	25
Nontraditional Investments	1	
	100%	100%

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its postretirement health care asset portfolio. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

Benefit Obligations A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table:

(Thousands of Dollars)		**2005**		**2004**
Change in Benefit Obligation				
Obligation at Jan. 1	$	929,125	$	775,230
Service cost		6,684		6,100
Interest cost		55,060		52,604
Plan amendments				(1,600)
Plan participants contributions		12,008		9,532
Actuarial gain (loss)		(3,175)		148,341
Benefit payments		(61,530)		(61,082)
Obligation at Dec. 31	$	938,172	$	929,125
Change in Fair Value of Plan Assets				
Fair value of plan assets at Jan. 1	$	318,667	$	285,861

Actual return on plan assets		14,507		21,950
Plan participants contributions		12,008		9,532
Employer contributions		68,211		62,406
Benefit payments		(61,530)		(61,082)
Fair value of plan assets at Dec. 31	$	351,863	$	318,667
Funded Status at Dec. 31				
Net obligation	$	586,309	$	610,458
Unrecognized transition obligation		(103,022)		(117,600)
Unrecognized prior service cost		15,736		17,914
Unrecognized loss		(364,745)		(383,026)
Accrued benefit liability recorded (a)	$	134,278	$	127,746

Measurement Date	**Dec. 31, 2005**	**Dec. 31, 2004**
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	5.75%	6.00%

(a) $3.1 million of the 2005 accrued benefit liability and $1.7 million of the 2004 accrued benefit liability relate to Xcel Energy s remaining obligation for companies that are now classified as discontinued operations.

Effective Dec. 31, 2004, Xcel Energy raised its initial medical trend assumption from 6.5 percent to 9.0 percent and lowered the ultimate trend assumption from 5.5 percent to 5.0 percent. The period until the ultimate rate is reached also was increased from two years to six years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy s retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects:

(Thousands of Dollars)		
1-percent increase in APBO components at Dec. 31, 2005	$	104,967
1-percent decrease in APBO components at Dec. 31, 2005	$	(87,450)
1-percent increase in service and interest components of the net periodic cost	$	8,177
1-percent decrease in service and interest components of the net periodic cost	$	(6,696)

Plan Changes - The employer subsidy for retiree medical coverage was eliminated for former New Century Energies, Inc. nonbargaining employees who retire after July 1, 2003.

Xcel Energy s subsidiary Viking was sold on Jan. 17, 2003. The sale created a one-time curtailment gain of $0.8 million. NRG participants withdrew from the retiree life plan, resulting in a $1.3 million one-time curtailment gain in 2003.

NRG employees participation in the Xcel Energy postretirement health care plan ended when NRG emerged from bankruptcy on Dec. 5, 2003. A settlement gain of $0.9 million was recognized.

Cash Flows The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy expects to contribute approximately $75 million during 2006.

Benefit Costs The components of net periodic postretirement benefit costs are:

(Thousands of Dollars)	2005	2004	2003
Service cost	$ 6,684	$ 6,100	$ 5,893
Interest cost	55,060	52,604	52,426
Expected return on plan assets	(25,700)	(23,066)	(22,185)
Curtailment gain			(2,128)
Settlement gain			(916)
Amortization of transition obligation	14,578	14,578	15,426
Amortization of prior service credit	(2,178)	(2,179)	(1,533)
Amortization of net loss gain	26,246	21,651	15,409
Net periodic postretirement benefit cost under SFAS No. 106(a)	74,690	69,688	62,392
Additional cost recognized due to effects of regulation	3,891	3,891	3,883
Net cost recognized for financial reporting	$ 78,581	$ 73,579	$ 66,275
Significant assumptions used to measure costs (income)			
Discount rate	6.00%	6.25%	6.75%
Expected average long-term rate of return on assets (pretax)	5.50-8.50%	5.50-8.50%	8.00-9.00%

(a) Includes amounts related to discontinued operations of $1.1 million of cost in 2005, $1.3 million of cost in 2004 and $(1.7) million of cost in 2003.

Projected Benefit Payments

The following table lists Xcel Energy s projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2006	$ 218,093	$ 63,966	$ 4,777	$ 59,189
2007	$ 221,166	$ 65,851	$ 5,196	$ 60,655
2008	$ 228,196	$ 67,635	$ 5,582	$ 62,053
2009	$ 234,663	$ 69,303	$ 5,936	$ 63,367
2010	$ 239,730	$ 70,851	$ 6,248	$ 64,603
2011-2015	$ 1,216,821	$ 366,454	$ 34,719	$ 331,735

11. Detail of Interest and Other Income, Net of Nonoperating Expenses

Interest and other income, net of nonoperating expenses, for the years ended Dec. 31 consists of the following:

(Thousands of Dollars)	2005	2004	2003
Interest income	$ 14,886	$ 21,534	$ 17,653
Equity income (loss) in unconsolidated affiliates	2,511	3,225	(1,108)
Gain (loss) on disposal of assets	1,308	4,725	(581)
Other nonoperating income	7,153	4,441	3,160
Interest expense on corporate-owned life insurance and other employee-related insurance policies	(25,000)	(24,601)	(21,320)
Other nonoperating expense	(1)	(8)	(3,038)
Total interest and other income (expense)	$ 857	$ 9,316	$ (5,234)

12. Derivative Instruments

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. Xcel Energy and its subsidiaries utilize, in accordance with approved risk management policies, a variety of derivative instruments to mitigate market risk and to enhance our operations. The use of these derivative instruments is discussed in further detail below.

Utility Commodity Price Risk Xcel Energy s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into both long- and short-term physical purchase and sales contracts for electric capacity, energy and other energy-related products, and for various fuels used for generation of electricity and in the natural gas utility operations. Commodity risk also is managed through the use of financial derivative instruments. Xcel Energy s utility subsidiaries utilize these derivative instruments to reduce the volatility in the cost of commodities acquired on behalf of our retail customers even though regulatory jurisdiction may provide for a dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments is done consistently with the state regulatory cost-recovery mechanism. Xcel Energy s risk-management policy allows it to manage market price risk within each rate-regulated operation to the extent such exposure exists.

Short-Term Wholesale and Commodity Trading Risk Xcel Energy s utility subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and other energy-related instruments. These activities are primarily focused on specific regions where market knowledge and experience have been obtained and are generally less than one year in length. Xcel Energy s risk-management policy allows management to conduct the marketing activity within approved guidelines and limitations as approved by our risk-management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

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

Foreign Currency Exchange Risk Due to the discontinuance of NRG and Xcel Energy International s operations in 2003, as discussed in Note 2 to the Consolidated Financial Statements, Xcel Energy no longer has material foreign currency exchange risk.

Types of and Accounting for Derivative Instruments

Xcel Energy and its subsidiaries use a number of different derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not qualifying for the normal purchases and normal sales exception, as defined by SFAS No. 133, as amended, are recorded at fair value. The classification of the fair value for these derivative instruments is dependent on the designation of a qualifying hedging relationship. The fair values of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The designation of a cash flow hedge permits the classification of fair value to be recorded within Other Comprehensive Income, to the extent effective. The designation of a fair value hedge permits a derivative instrument s gains or losses to offset the related results of the hedged item in the Consolidated Statements of Operations, to the extent effective.

SFAS No. 133, as amended, requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. Xcel Energy and its subsidiaries formally document hedging relationships, including, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk-management objectives and strategies for undertaking the hedged transaction. Xcel Energy and its subsidiaries also formally assess, both at inception and on an ongoing basis, if required, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

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

Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The types of qualifying hedging transactions that Xcel Energy and its subsidiaries are currently engaged in are discussed below.

Cash Flow Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a cash flow hedge is recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument s change in fair value is recognized in current earnings.

Commodity Cash Flow Hedges Xcel Energy s utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At Dec. 31, 2005, Xcel Energy had various commodity-related contracts classified as cash flow hedges extending through 2009. The fair value of these cash flow hedges is recorded in either Other Comprehensive Income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. Amounts deferred in these accounts are recorded in earnings as the hedged purchase or sales transaction is settled. This could include the purchase or sale of energy or energy-related products, the use of natural gas to generate electric energy or gas purchased for resale.

As of Dec. 31, 2005, Xcel Energy had no amounts in Accumulated Other Comprehensive Income related to commodity cash flow hedge contracts that are expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Xcel Energy had no ineffectiveness related to commodity cash flow hedges during the years ended Dec. 31, 2005 and 2004.

Interest Rate Cash Flow Hedges **Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively**

112

Interest Rate Cash Flow Hedges Xcel Energy and its subsidiaries enter into interest rate swap instruments that ef

fix the interest payments on certain floating-rate debt obligations. These derivative instruments are designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2005, Xcel Energy had net losses related to interest rate swaps of approximately $0.8 million in Accumulated Other Comprehensive Income that it expects to recognize in earnings during the next 12 months.

Xcel Energy and its subsidiaries also enter into interest rate lock agreements, including treasury-rate locks and forward starting swaps, that effectively fix the yield or price on a specified treasury security for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2005, Xcel Energy had net gains related to settled interest rate lock agreements of approximately $1.4 million in Accumulated Other Comprehensive Income that it expects to recognize in earnings during the next 12 months.

Xcel Energy had no ineffectiveness related to interest rate cash flow hedges during the years ended Dec. 31, 2005 and 2004.

Financial Impact of Qualifying Cash Flow Hedges **The impact of qualifying cash flow hedges on Xcel Energy s Accumulated Other Comprehensive Income, included in the Consolidated Statements of Stockholders Equity, is detailed in the following table:**

(Millions of Dollars)		
Accumulated other comprehensive income related to hedges at Dec. 31, 2002	$	22.1
After-tax net unrealized gains related to derivatives accounted for as hedges		24.1
After-tax net realized gains on derivative transactions reclassified into earnings		(38.1)
Accumulated other comprehensive income related to hedges at Dec. 31, 2003	$	8.1
After-tax net unrealized gains related to derivatives accounted for as hedges		1.6
After-tax net realized gains on derivative transactions reclassified into earnings		(9.6)
Accumulated other comprehensive income related to hedges at Dec. 31, 2004	$	0.1
After-tax net unrealized gains related to derivatives accounted for as hedges		4.5
After-tax net realized gains on derivative transactions reclassified into earnings		(13.4)
Accumulated other comprehensive loss related to hedges at Dec. 31, 2005	$	(8.8)

Fair Value Hedges

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

Interest Rate Fair Value Hedges Xcel Energy enters into interest rate swap instruments that effectively hedge the fair value of fixed-rate debt. The fair market value of Xcel Energy s interest rate swaps at Dec. 31, 2005, was a liability of approximately $14.1 million.

Normal Purchases or Normal Sales Contracts

Xcel Energy s utility subsidiaries enter into contracts for the purchase and sale of various commodities for use in their business operations. SFAS No. 133, as amended, requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133, as amended, as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In addition, normal purchases and normal sales contracts must have a price based on an underlying that is clearly and closely related to the asset being purchased or sold. An underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event, such as a scheduled payment under a contract.

Xcel Energy evaluates all of its contracts when such contracts are entered to determine if they are derivatives and, if so, if they qualify to meet the normal designation requirements under SFAS No. 133, as amended. None of the contracts entered into within the commodity trading operations qualify for a normal designation.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under GAAP.

The following discussion briefly describes the use of derivative commodity and financial instruments at Xcel Energy and its subsidiaries, and discloses the respective fair values at Dec. 31, 2005 and 2004.

Commodity Trading Instruments At Dec. 31, 2005 and 2004, the fair value of commodity trading contracts was $3.9 million and $0.0 million, respectively.

Hedging Contracts The fair value of qualifying cash flow hedges at Dec. 31, 2005 and 2004 was $4.1 million and $(24.6) million, respectively.

Financial Instruments Xcel Energy and its subsidiaries had interest rate swaps outstanding with a fair value that was a liability of approximately $44.7 million at Dec. 31, 2005. On Dec. 31, 2004, subsidiaries of Xcel Energy had interest rate swaps outstanding with a fair value that was a liability of approximately $30 million.

13. Financial Instruments

The estimated Dec. 31 fair values of Xcel Energy s financial instruments, separately identifying amounts that are within continuing operations and within discontinued operations, are as follows:

	2005		2004	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Continuing Operations:				
Nuclear decommissioning fund	$ 1,047,592	$ 1,047,592	$ 918,442	$ 918,442
Other investments	$ 24,286	$ 24,050	$ 43,141	$ 43,031
Long-term debt, including current portion	$ 6,733,284	$ 7,245,346	$ 6,716,675	$ 7,391,616
Discontinued Operations:				
Long-term debt, including current portion	$	$	$ 24,800	$ 26,333

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates. The fair values of Xcel Energy s debt securities in an external nuclear decommissioning fund and other investments are estimated based on quoted market prices for those or similar investments. The fair values of Xcel Energy s long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2005 and 2004. These fair value estimates have not been comprehensively revalued for purposes of these Consolidated Financial Statements since that date, and current estimates of fair values may differ significantly.

The following tables provide the external decommissioning fund s approximate gains, losses and proceeds from the sale of securities for the years ended Dec. 31:

(Thousands of Dollars)	2005	2004	2003
Realized gains	$ 8,967	$ 16,578	$ 4,999
Realized losses	$ 8,990	$ 20,180	$ 6,025
Proceeds from sale of securities	$ 489,697	$ 223,135	$ 57,768

(Thousands of Dollars)	2005	2004
Unrealized gains	$ 253,991	$ 240,960
Unrealized losses	$ 10,558	$ 2,703

Xcel Energy provides guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantee. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral.

On Dec. 31, 2005, Xcel Energy had the following amount of guarantees and exposure under these guarantees, including those related to Seren and Xcel Energy Argentina, which are components of discontinued operations:

(Millions of Dollars) Nature of Guarantee	**Guarantor**	**Guarantee Amount**	**Current Exposure**	**Term or Expiration Date**	**Triggering Event Requiring Performance**	**Assets Held as Collateral**
Guarantee performance and payment of surety bonds for itself and its subsidiaries (d)(h)	Xcel Energy	$ 132.9	(a)	2006 - 2008, 2012, 2014, 2015 and 2022	(e)	N/A
Guarantee performance and payment of surety bonds	PSCo	$ 0.50	(a)	2006	(e)	N/A
Guarantee the indemnification obligations of Xcel Energy Wholesale Group Inc. under a stock purchase agreement	Xcel Energy	$ 17.50	$	2010	(c)	N/A
Guarantee the indemnification obligations of Xcel Energy Argentina under a stock purchase agreement	Xcel Energy	$ 14.70	$	Continuing	(c)	N/A
Guarantee the indemnification obligations of Seren under an asset purchase agreement	Xcel Energy	$ 12.50	$	Continuing	(c)	N/A
Guarantee of customer loans to encourage business growth and expansion	NSP-Wisconsin	$ 0.20	$ 0.20	2006	(f)	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$ 0.12	$ 0.12	2006	(b)	(g)
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$ 7.65	$	Continuing	(b)	N/A

(a) The total exposure of this indemnification cannot be determined. Xcel Energy believes the exposure to be significantly less than the total amount of the outstanding bonds.

(b) Nonperformance and/or nonpayment.

(c) Losses caused by default in performance of covenants or breach of any warranty or representation in the purchase agreement.

(d) Includes one performance bond with a notional amount of $11.1 million that guarantees the performance of Planergy Housing Inc., a subsidiary of Xcel Energy that was sold to Ameresco Inc. on Dec. 12, 2003. Ameresco Inc.

has agreed to indemnify Xcel Energy for any liability arising out of any surety bond.

(e) Failure of Xcel Energy or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(f) Non-timely payment of the obligations or at the time the debtor becomes the subject of bankruptcy or other insolvency proceedings.

(g) Security interest in underlying receivable agreements.

(h) Xcel Energy agreed to indemnify an insurance company in connection with surety bonds they may issue or have issued for Utility Engineering up to $80 million. The Xcel Energy indemnification will be triggered only in the event that Utility Engineering has failed to meet its obligations to the surety company.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2005, there was $35.2 million of letters of credit outstanding. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

14. Commitments and Contingencies

Commitments

Legislative Resource Commitments In 1994, NSP-Minnesota received Minnesota legislative approval for on-site temporary spent-fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Commitments related to the 17 dry cask storage containers approved in 1994 have been fulfilled. As the result of legislative amendments in 2003, NSP-Minnesota is authorized to use as many dry cask storage containers as necessary to operate the plant through 2014. Current estimates indicate that this will require 29 dry cask storage containers. As of Dec. 31, 2005, NSP-Minnesota had filled and placed 20 dry cask containers in storage at Prairie Island.

The 2003 legislation transfers the primary authority concerning future spent-fuel storage issues from the Legislature to the MPUC. In January 2005, NSP-Minnesota filed an application with the MPUC for a certificate of need for up to 30 dry cask storage containers at the Monticello nuclear plant so that it can continue to operate beyond 2010. Xcel Energy expects a decision from the MPUC later this year. NSP-Minnesota also filed its request with the U.S. Nuclear Regulatory Commission (NRC) on March 24, 2005, for a 20-year extension to Monticello s operating license. If a certificate of need is granted, it is stayed until the following June to provide the Minnesota Legislature the opportunity to review the MPUC s action if it is determined appropriate. The 2003 legislation also requires NSP-Minnesota to add at least 300 megawatts of additional wind power by 2010, with an option to own 100 megawatts of this power.

Furthermore, payments during the remaining operating life of the Prairie Island plant are required. These payments include: $2.25 million per year to the Prairie Island Tribal Community beginning in 2004; 5 percent of NSP-Minnesota s conservation program expenditures (estimated at $2 million per year) to the University of Minnesota for renewable energy research; and an increase in funding commitments to the previously established Renewable Development Fund to $16 million per year beginning in 2003. All of the cost increases to NSP-Minnesota from these required payments and funding commitments are expected to be recoverable in Minnesota retail customer rates, mainly through existing cost-recovery mechanisms. Funding commitments to the Renewable Development Fund would terminate after the Prairie Island plant discontinues operation unless the MPUC determines that NSP-Minnesota failed to make a good faith effort to store or dispose of the spent fuel out of state, in which case NSP-Minnesota would have to make payments in the amount of $7.5 million per year.

Capital Commitments The estimated cost as of Dec. 31, 2005, of the capital expenditure programs and other capital requirements of Xcel Energy and its subsidiaries is approximately $1.6 billion in 2006, $1.6 billion in 2007 and $1.4 billion in 2008.

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, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy s long-term energy needs. In addition, Xcel Energy s ongoing evaluation of compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Leases Xcel Energy and its subsidiaries lease a variety of equipment and facilities used in the normal course of business. Two of these leases qualify as capital leases and are accounted for accordingly. The capital leases contractually expire in 2025 and 2029. The assets and liabilities acquired under capital leases are recorded at the lower of fair market value or the present value of future lease payments, and are depreciated over their actual contract term in accordance with practices allowed by regulators. Depreciation of assets under capital leases is included in depreciation expense for 2005 and 2004.

Following is a summary of property held under capital leases:

(Millions of Dollars)	2005	2004
Storage, leaseholds and rights	$ 40.5	$ 40.5
Gas pipeline	20.7	20.7
	61.2	61.2
Accumulated depreciation	(13.6)	(12.3)
Total property held under capital leases	$ 47.6	$ 48.9

The remainder of the leases, primarily for office space, railcars, trucks, cars and power-operated equipment, are accounted for as operating leases. Rental expense under operating lease obligations for continuing operations was approximately $57.2 million, $57.5 million and $65.0 million for 2005, 2004 and 2003, respectively.

Future commitments under operating and capital leases for continuing operations are:

(Millions of Dollars)	Operating Leases	Capital Leases
2006	$ 41	$ 7
2007	$ 34	$ 6
2008	$ 31	$ 6
2009	$ 27	$ 6
2010	$ 21	$ 6
Thereafter	$ 54	$ 68
Total minimum obligation		$ 99
Interest component of obligation		(51)
Present value of minimum obligation		$ 48

Technology Agreement Xcel Energy has a contract that extends through 2015 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at our option, although there are financial penalties for early termination. In 2005, Xcel Energy paid IBM $137.7 million under the contract and $3.5 million for other project business. The contract also has a committed minimum payment each year from 2006 through September 2015.

Fuel Contracts Xcel Energy and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2006 and 2027. In total, Xcel Energy is committed to the minimum purchase of approximately $2.8 billion of coal, $117.6 million of nuclear fuel and $2.7 billion of natural gas, including $1.0 billion of natural gas storage and transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy s risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

Purchased Power Agreements The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Certain contractual payment obligations are adjusted based on indexes. However, the effects of price adjustments are mitigated through cost-of-energy rate adjustment mechanisms.

At Dec. 31, 2005, the estimated future payments for capacity that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Thousands of Dollars)		
2006	$	564,669
2007		579,333
2008		592,655
2009		574,145
2010		555,228
2011 and thereafter		3,439,683
Total	$	6,305,713

Environmental Contingencies

Xcel Energy and its subsidiaries have been, or are currently involved with, the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense for such unrecoverable amounts in its Consolidated Financial Statements.

Site Remediation Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries and some other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including the following categories of sites:

The site of a former federal uranium enrichment facility;

Sites of former manufactured gas plants (MGPs) operated by Xcel Energy subsidiaries or predecessors; and

Third-party sites, such as landfills, to which Xcel Energy is alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes.

Xcel Energy records a liability when enough information is obtained to develop an estimate of the cost of environmental remediation and revises the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, assumptions are made when facts are not fully known. For instance, assumptions may be made about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution-control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution-control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

Estimates are revised as facts become known. At Dec. 31, 2005, the liability for the cost of remediating these sites was estimated to be $27.8 million, of which $8.8 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

Insurance coverage;

Other parties that have contributed to the contamination; and

Customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. Estimates have been recorded for Xcel Energy s future costs for these sites.

Federal Uranium Enrichment Facility

Approximately $0.5 million of the long-term liability and $4.8 million of the current liability relate to a DOE assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. These environmental liabilities do not include accruals recorded and collected from customers in rates for future nuclear fuel disposal costs or decommissioning costs related to NSP-Minnesota s nuclear generating plants. See Note 15 to the Consolidated Financial Statements for further discussion of nuclear obligations.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site NSP-Wisconsin was named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin, which was previously an MGP facility, and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior s Chequemegon Bay adjoining the park.

As an interim action, NSP-Wisconsin proposed, and the Wisconsin Department of Natural Resources (WDNR) approved, a coal tar removal and groundwater treatment system for one area of concern at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer under the former MGP site to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the United States EPA in determining which sites require further investigation. On Dec. 7, 2004, the EPA approved, with minor contingencies, NSP-Wisconsin s proposed work plan to complete the remedial investigation and feasibility study. On Feb. 1, 2005, NSP-Wisconsin submitted its revised work plan to the EPA addressing all of the contingencies raised with the previous proposal. The final approval results in specific delineation of the investigative fieldwork and scientific assessments that must be performed. A determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2007 or 2008. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. In 2005, NSP-Wisconsin spent $2.8 million in the development of the work plan, the interim response action and other matters related to the site.

The WDNR and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility, NSP-Wisconsin s liability for the cost of remediating the Ashland site is not determinable. NSP-Wisconsin has recorded a liability of $19.7 million for its potential liability for remediating the Ashland site. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, the recorded liability is based upon the minimum of the estimated range of remediation costs, using information available to date and reasonably effective remedial methods.

On July 2, 2004, the WDNR sent NSP-Wisconsin an invoice for recovery of past costs incurred at the Ashland site between 1994 and March 2003 in the amount of $1.4 million. On Oct. 19, 2004, the WDNR, represented by the Wisconsin Department of Justice, filed a lawsuit in Wisconsin state court for reimbursement of the past costs. This lawsuit has been stayed until further action by either party. NSP-Wisconsin is reviewing the invoice to determine whether all costs charged are appropriate and has recorded an estimate of its potential liability. All appropriate insurance carriers have been notified of the WDNR s invoice and the lawsuit, and will be invited to participate in any future efforts to address the WDNR s actions. All costs paid to the WDNR are expected to be recoverable in rates.

In addition to potential liability for remediation and WDNR oversight costs, NSP-Wisconsin may have liability for natural resource damages, including the assessment thereof (collectively NRDA) at the Ashland site. Section 107 of the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) as amended, provides that a natural resource damages trustee may recover for injury to, destruction or loss of natural resources, including the reasonable costs of assessment, resulting from releases of hazardous substances. Similarly, Section 311 of the Federal Water Pollution Control Act (or Clean Water Act) provides the federal and state governments with the ability to recover costs incurred in the restoration or replacement of natural resources damaged or destroyed as a result of a hazardous substance discharge. In addition to liability for injuries to or loss of services caused by a release from the Ashland site, NSP-Wisconsin could face exposure for additional indirect injuries that could result from the implementation of various remedial technologies during the cleanup phase of the project. NSP-Wisconsin has indicated to the relevant natural resource trustees its intent to pursue a cooperative assessment approach to the NRDA for the Ashland site whereby the question of natural resource damages is assessed and resolved in tandem with the studies required for selection of a cleanup remedy or remedies. It is, however, unknown at this time whether a cooperative assessment NRDA approach will be adopted at the Ashland site. Therefore, NSP-Wisconsin is not able to estimate its potential exposure for natural resource damages at the site, but has recorded an estimate of its potential liability based upon the minimum of its estimated range of potential exposure.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process. Once approved by the PSCW, deferred MGP remediation costs, less carrying costs, are historically amortized over four or six years. Carrying costs vary directly with the balance in the deferred account and for the period 1995-2005 are estimated to total approximately $1.8 million.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers.

Fort Collins Manufactured Gas Plant Site Prior to 1926, Poudre Valley Gas Co., a predecessor of PSCo, operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the Poudre Valley Gas Co., PSCo shut down the MGP site and has sold most of the property. An oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. On Nov. 10, 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co., under which PSCo performed remediation and monitoring work. PSCo has substantially completed work at the site, with the exception of ongoing maintenance and monitoring. In May 2005, PSCo filed a natural gas rate case with the CPUC requesting recovery of cleanup costs at the Fort Collins MGP plant spent through March 2005, which amounted to $6.2 million to be amortized over four years. Xcel Energy 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, with rates effective Feb. 6, 2006.

In April 2005, PSCo brought a contribution action against Schrader Oil Co. and related parties alleging Schrader Oil Co. released hazardous substances into the environment and these releases increased the migration and environmental impact of the MGP byproducts at the site. PSCo requested damages, including a portion of the costs PSCo incurred to investigate and remove contaminated sediments from the Cache la Poudre River. On Dec. 14, 2005, the court denied Schrader s request to dismiss the PSCo suit. On Jan. 3, 2006, Schrader filed a response to the PSCo complaint and a counterclaim against PSCo for its response costs under the CERCLA and under the Resource Conservation and Recovery Act (RCRA). Schrader has alleged as part of its counterclaim an imminent and substantial endangerment of its property as defined by RCRA. PSCo believes the allegations with respect to PSCo are without merit and will vigorously defend itself.

Third Party and Other Environmental Site Remediation

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation. See additional discussion of asset retirement obligations elsewhere in Note 14. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects

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. Xcel Energy believes that the additional $0.9 million of costs incurred may be recovered in a future case.

In December 2003, a homeowners   association petitioned the EPA to assess the threat of a natural gas release from the Leyden facility pursuant to Section 105(d) of the CERCLA. The EPA completed its review in October 2004 and concluded that the risk to nearby residents is relatively low. The EPA referred the matter to its RCRA program. On Nov. 24, 2004, the EPA sent a letter to the COGCC requesting that the COGCC contact Xcel Energy and request certain information concerning the closure. To date no formal request has been received by PSCo.

On Aug. 17, 2005, the EPA requested information from PSCo regarding the compliance status of the Leyden facility under the federal Clean Air Act (CAA). On Sept. 19, 2005, PSCo responded to the requests for information. PSCo believes the

Leyden facility is in compliance with the CAA and other applicable state and federal environmental laws. Xcel Energy cannot predict the ultimate outcome of this inquiry, however, any consequence is not expected to have a material impact.

Polychlorinated Biphenyl (PCB) Storage and Disposal In August 2004, SPS 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 contends the fine for the alleged violation is approximately $1.2 million. SPS is contesting the fine and is in discussions with the EPA.

Cunningham Station Groundwater Cunningham Station is a natural gas-fired power plant constructed in the 1960s by SPS and has 28 water wells installed on its water rights. The well field provides water for boiler makeup, cooling water and potable water. Following an acid release in 2002, groundwater samples revealed elevated concentrations of inorganic salt compounds not related to the release. The contamination was identified in wells located near the plant buildings. The source of contamination is thought to be leakage from ponds that receive blow down water from the plant. In response to a request by the New Mexico Environment Department (NMED), SPS prepared a corrective action plan to address the groundwater contamination. Under the plan submitted to the NMED, SPS agreed to control leakage from the plant blow down ponds through construction of a new lined pond, additional irrigation areas to minimize percolation, and installation of additional wells to monitor groundwater quality. On June 23, 2005, NMED issued a letter approving the corrective action plan. The action plan is subject to continued compliance with New Mexico regulations and oversight by the NMED. These actions, which are considered future improvements, are estimated to cost approximately $3.8 million through 2008 and will be capitalized or expensed as incurred.

Other Environmental Requirements

Clean Air Interstate and Mercury Rules - In March 2005, the EPA issued two significant new air quality rules. The Clean Air Interstate Rule (CAIR) further regulates sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions, and the Clean Air Mercury Rule (CAMR) regulates mercury emissions from power plants for the first time.

The objective of the CAIR is to cap emissions of SO_2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy s service territory. Xcel Energy generating facilities in other states are not affected. When fully implemented, CAIR will reduce SO_2 emissions in 28 eastern states and the District of Columbia by over 70 percent, and NOx emissions by over 60 percent from 2003 levels. It is designed to address the transportation of fine particulates, ozone and emission precursors to nonattainment downwind states. CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

On July 11, 2005, SPS, the City of Amarillo, Texas and Occidental Permian LTD filed a lawsuit against the EPA and a request for reconsideration with the agency to exclude West Texas from the CAIR. El Paso Electric Co. joined in the request for reconsideration.

Xcel Energy and SPS advocated that West Texas should be excluded from CAIR because it does not contribute significantly to nonattainment with the fine particulate matter National Ambient Air Quality Standard in any downwind jurisdiction. They argued that:

Emissions from plants located in the Texas panhandle are more than 1,000 kilometers away from cities like Chicago, St. Louis and Indianapolis and have no measurable impact on their air quality.

The EPA should not arbitrarily include the entire state of Texas in the rule. As a result of its size, there are significant differences in the air quality impact of plants in the different regions of Texas.

The EPA has precedent for dividing the state into two regions. As part of the Texas Air Quality strategy, the Texas Commission on Environmental Quality split the state and imposed different requirements on West Texas. The Bush administration adopted a similar approach in its proposed Clear Skies Act.

The EPA excluded Oklahoma and Kansas from CAIR, but imposes CAIR s burdens on plants in West Texas. Emissions from West Texas must pass through Oklahoma and Kansas and over power plants in those states that are not subject to the rule before reaching the downwind cities the rule is designed to protect.

Under CAIR s cap-and-trade structure, SPS can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. Based on the preliminary analysis of various scenarios of capital investment and allowance purchase, capital investments could range from $30 million to $300 million, and allowance purchases or increased operating and maintenance expenses could range from $20 million to $30 million per year, beginning in 2011 based on the cost of allowance on Feb. 15, 2006. This does not include other costs that SPS will have to incur to comply with the EPA s new mercury emission control regulations, which will apply to SPS plants.

In addition, Minnesota and Wisconsin will be included in CAIR, and Xcel Energy has generating facilities in these states that will be impacted. Preliminary estimates of capital expenditures associated with compliance with CAIR in Minnesota and Wisconsin range from $30 million to $40 million. Xcel Energy is not challenging CAIR in these states.

These cost estimates represent one potential scenario on complying with CAIR, if West Texas is not excluded. There is uncertainty concerning implementation of CAIR. States are required to develop implementation plans within 18 months of the issuance of the new rules and have a significant amount of discretion in the implementation details. Legal challenges to CAIR rules could alter their requirements and/or schedule. The uncertainty associated with the final CAIR rules makes it difficult to project the ultimate amount and timing of capital expenditures and operating expenses.

While Xcel Energy expects to comply with the new rules through a combination of additional capital investments in emission controls at various facilities and purchases of emission allowances, it is continuing to review the alternatives. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers.

The EPA s CAMR also uses a national cap-and-trade system and is designed to achieve a 70 percent reduction in mercury emissions. It affects all coal- and oil-fired generating units across the country that are greater than 25 megawatts. Compliance with this rule also occurs in two phases, with the first phase beginning in 2010 and the second phase in 2018. States will be allocated mercury allowances based on coal type and their baseline heat input relative to other states. Each electric generating unit will be allocated mercury allowances based on its percentage of total coal heat input for the state. Similar to CAIR, states can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

Under CAMR, Xcel Energy can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. Estimating the cost of compliance with CAMR is difficult because technologies specifically designed for control of mercury are in the early stages of development and there is no established market on which to base the cost of mercury allowances. Xcel Energy s preliminary analysis for phase I compliance suggests capital costs of approximately $20 million and increased operating and maintenance expense ranging between $10 million and $20 million, beginning in 2010. Further testing is planned during 2006 to confirm these costs or determine whether different measures will be necessary, which could result in higher costs. Additional costs will be incurred to meet phase II requirements in 2018.

The Minnesota Legislature is expected to consider legislation in the 2006 session that could require up to a 90 percent reduction in mercury emissions from coal-fueled power plants provided the MPUC determines that it is technically feasible and economically reasonable to do so. The cost impact of this potential legislation is unknown. The legislation is expected to allow for cost recovery by the utility.

Regional Haze Rules On June 15, 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements. Some of these facilities are located in regions where CAIR is effective. CAIR has precedence over BART. Therefore, BART requirements will be deemed to be met through compliance with CAIR requirements.

States must develop their implementation plans by December 2007. States will identify the facilities that will have to reduce emissions under BART and then set BART emissions limits for those facilities. Colorado is the first state in Xcel Energy s region to earnestly begin its BART rule development as the first step toward the December 2007 deadline. Xcel Energy is actively involved in the stakeholder process in Colorado and will also be involved as other states begin their process. Due to the uncertainties of the many decisions involved in this process, Xcel Energy is not able to estimate the cost impact at this time.

Federal Clean Water Act The federal Clean Water Act addresses the environmental impact of cooling water intakes. In July 2004, the EPA published phase II of the rule that applies to existing cooling water intakes at steam-electric power plants. The rule will require Xcel Energy to perform additional environmental studies at several power plants in Minnesota, Wisconsin and Colorado to determine the impact the facilities may be having on aquatic organisms vulnerable to injury. If the studies determine the plants are not meeting the new performance standards established by the phase II rule, physical and/or operational changes may be required at these plants. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved, including unresolved third-party legal challenges to the federal rule. Preliminary cost estimates range from less than $1 million at some plants to more than $10 million at others, depending on site-specific circumstances. Based on the limited information available, total capital and operating and maintenance costs to Xcel Energy are estimated at approximately $30 million over the next five to 10 years. Actual costs may be higher or lower depending on the final resolution of legal challenges to the rule, as well as pending state and federal decisions regarding interpretation of specific rule requirements.

PSCo Notice of Violation On July 1, 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche and Pawnee plants in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. It believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo also believes that the projects would be expressly authorized under the EPA s NSR equipment replacement rulemaking promulgated in October 2003. On Dec. 24, 2003, the U.S. Court of Appeals for the District of Columbia circuit stayed this rule while it considers challenges to it. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position. As required by the CAA, the EPA met with Xcel Energy in September 2002 to discuss the NOV.

On March 10, 2005, the Rocky Mountain Environmental Labor Coalition (RMELC) provided notice to PSCo of its intent to sue PSCo for alleged violations of the CAA at the Comanche plant. The notice of intent to sue alleges PSCo has violated the CAA s Prevention of Significant Deterioration regulations based on allegations that maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. The allegations are the same as those presented in the NOV. On June 9, 2005, Citizens for Clean Air and Water in Pueblo/Southern Colorado (CCAP) and Leslie Glustrom provided notice of intent to sue PSCo for alleged violations of the CAA at the Comanche Plant. The allegations in the notice of intent to sue by CCAP and Ms. Glustrom are substantially identical to those of RMELC. PSCo believes the allegations with respect to PSCo are without merit and will vigorously defend itself in any suit which may be filed. Currently, Xcel Energy is not able to estimate any potential loss.

Asset Retirement Obligations

Xcel Energy adopted Statement of Financial Accounting Standard SFAS No. 143 Accounting for Asset Retirement Obligations (SFAS No. 143) effective Jan. 1, 2003. Xcel Energy records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets. This liability will be increased over time by applying the interest method of accretion to the liability, and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations (FIN No. 47) to clarify the scope and timing of liability recognition for conditional asset retirement obligations pursuant to SFAS No. 143. The interpretation requires that a liability be recorded for the fair value of an asset retirement obligation, if the fair value is estimable, even when the obligation is dependent on a future event. FIN No. 47 further clarified that uncertainty surrounding the timing and method of settlement of the obligation should be factored into the measurement of the conditional asset retirement obligation rather than affect whether a liability should be recognized. Xcel Energy implemented FIN No. 47 as of Dec. 31, 2005. Included in these financial statements is the recognition of a cumulative change in accounting and disclosure of the liability on a pro forma basis.

Recorded Asset Retirement Obligations (ARO) Asset retirement obligations have been recorded for nuclear production, steam production, electric transmission and distribution system, natural gas distribution system and office buildings. The steam production obligation includes asbestos, ash-containment facilities and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. Generally, this asbestos abatement removal obligation originated in 1973 with the Clean Air Act, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. Asset retirement obligations also have been recorded for NSP-Minnesota, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination date on the ARO recognition for ash-containment facilities at steam plants was the in-service date of various facilities.

Xcel Energy recognized an ARO for the retirement costs of natural gas mains at NSP-Minnesota, NSP- Wisconsin and PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. The electric transmission and distribution ARO consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured at Dec. 31, 2005. The asset retirement cost was set to this recognized obligation and no cumulative effect adjustment was shown.

A liability has also been recorded in previous years for nuclear decommissioning of an NSP-Minnesota steam production plant. This plant began operating as a nuclear production facility in 1964 before being converted to a steam production peaking facility in 1969. For the nuclear assets, the asset retirement obligation is associated with the decommissioning of two NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originates with the in-service date of the facility. Monticello began operation in 1971. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively. See Note 15 to the Consolidated Financial Statements for further discussion of nuclear obligations.

A reconciliation of the beginning and ending aggregate carrying amounts of Xcel Energy s asset retirement obligations is shown in the table below for the 12 months ended Dec. 31, 2005 and 2004:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2005	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2005
Electric Utility Plant:						
Steam production asbestos	$	$ 5,917	$	$ 28,406	$	$ 34,323
Steam production ash containment		4,916		16,018		20,934
Steam production retirement	3,002			150		3,152
Nuclear production decommissioning	1,088,087			70,736	26,145	1,184,968
Electric transmission and distribution		2,350				2,350
Gas Utility Plant:						
Gas transmission and distribution		43,245				43,245
Common Utility and Other Property:						
Common general plant asbestos		575		2,459		3,034
Total liability	$ 1,091,089	$ 57,003	$	$ 117,769	$ 26,145	$ 1,292,006

(Thousands of Dollars)	Beginning Balance Jan. 1, 2004	Liabilities Recognized	Liabilities Settled	Accretion	Revisions To Prior Estimates	Ending Balance Dec. 31, 2004
Electric Utility Plant:						
Steam production retirement	2,860			142		3,002
Nuclear production decommissioning	1,021,669			66,418		1,088,087
Total liability	$ 1,024,529	$	$	$ 66,560	$	$ 1,091,089

The fair value of NSP-Minnesota assets legally restricted, for purposes of settling the nuclear asset retirement obligation is $1.1 billion as of Dec. 31, 2005, including external nuclear decommissioning investment funds and internally funded amounts.

Cumulative Effect of FIN No. 47 In March 2005, the FASB issued FIN No. 47. The interpretation clarified the term conditional asset retirement obligation as used in SFAS No. 143. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. If Xcel Energy had implemented FIN No. 47 at Jan. 1, 2004, the liability for asset retirement obligations would have increased by $52.2 million. The same liability at Dec. 31, 2004 would have increased by $55.2 million. A summary of the accounting for the initial adoption of FIN No. 47, as of Dec. 31, 2005, is as follows:

(Thousands of Dollars)	Plant Assets	Regulatory Assets	Long-Term Liabilities
Reflect retirement obligation when liability incurred	$ 57,003	$	$ 57,003
Record accretion of liability to adoption date		46,883	46,883
Record depreciation of plant to adoption date	(8,283)	8,283	
Net impact of FASB Interpretation No. 47	$ 48,720	$ 55,166	$ 103,886

Indeterminate Asset Retirement Obligations PSCo has underground gas storage facilities that have special closure requirement for which the final removal date cannot be determined.

Removal Costs Xcel Energy accrues an obligation for plant removal costs for other generation, transmission and distribution facilities of its utility subsidiaries. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, the utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accordingly, the recorded amounts of estimated future removal costs are considered Regulatory Liabilities under SFAS No. 71. Removal costs by entity are as follows at Dec. 31:

(Millions of Dollars)		**2005**		**2004**
NSP-Minnesota	$	334	$	323
NSP-Wisconsin		86		81
PSCo		377		383
SPS		98		104
Total Xcel Energy	$	895	$	891

Nuclear Insurance NSP-Minnesota s public liability for claims resulting from any nuclear incident is limited to $10.8 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $10.5 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $100.6 million for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $15 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.1 billion for each of NSP-Minnesota s two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $14.8 million for business interruption insurance and $26.5 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

In the normal course of business, Xcel Energy is subject to claims and litigation arising from prior and current operations. Xcel Energy is actively defending these matters and has recorded a reasonable liability related to the probable cost of settlement or other disposition when it can be reasonably estimated. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy s financial position and results of operations.

Bender et al. vs. Xcel Energy On July 2, 2004, five former NRG officers filed a lawsuit against Xcel Energy in the U.S. District Court for the District of Minnesota. The lawsuit alleges, among other things, that Xcel Energy violated the Employee Retirement Income Security Act of 1974 (ERISA) by refusing to make certain deferred compensation payments to the plaintiffs. The complaint also alleges interference with ERISA benefits, breach of contract related to the nonpayment of certain stock options and unjust enrichment. The complaint alleges damages of approximately $6 million. Xcel Energy believes the suit is without merit. On Jan. 19, 2005, Xcel Energy filed a motion for summary judgment. On July 26, 2005, the court issued an order granting Xcel Energy s motion for summary judgment in part with respect to claims for interference with ERISA benefits, breach of contract for nonpayment of stock options and unjust enrichment. The court denied Xcel Energy s motion in part with respect to the allegations of nonpayment of deferred compensation benefits. Plaintiffs and Xcel Energy have filed additional cross motions for summary judgment, with oral arguments presented on Feb. 24, 2006. The court has also ordered this lawsuit to be trial-ready by Feb. 1, 2006.

Carbon Dioxide Emissions Lawsuit On July 21, 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO_2) emissions. The other utilities include American Electric Power Co., Southern

Co., Cinergy Corp. and Tennessee Valley Authority. CO_2 is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or gas-fired power plants. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. In October 2004, Xcel Energy and four other utility companies filed a motion to dismiss the lawsuit, contending, among other reasons, that the lawsuit is an attempt to usurp the policy-setting role of the U.S. Congress and the president. On Sept. 19, 2005, the judge granted the defendants motion to dismiss on constitutional grounds. Plaintiffs have filed a notice of appeal.

Department of Labor Audit In 2001, Xcel Energy received notice from the Department of Labor (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 is 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, the DOL submitted two additional requests for information related to the investigation and has not indicated that they are prepared to close the file, or in the alternative to assert charges against Xcel Energy or the pension plan.

Texas-Ohio Energy, Inc. vs. Centerpoint Energy et al. On Nov. 19, 2003, a class action complaint filed in the U.S. District Court for the Eastern District of California by Texas-Ohio Energy, Inc. was served on Xcel Energy naming e prime as a defendant. The lawsuit, filed on behalf of a purported class of large wholesale natural gas purchasers, alleges that e prime falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California. The case has been conditionally transferred by the Multi-District Litigation (MDL) Panel to U.S. District Judge Pro, in Nevada, who is the judge assigned to western area wholesale natural gas marketing litigation. In an order entered April 8, 2005, Judge Pro granted the defendants motion to dismiss based on the filed rate doctrine. On May 9, 2005, plaintiffs filed an appeal of this decision to the 9th Circuit Court of Appeals.

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 U.S. Court of Appeals for the Second Circuit challenging the class certification. On Dec. 5, 2005, e prime reached a tentative settlement with the plaintiffs that will require court approval. The settlement will be paid by e prime and is not expected to have a material financial impact on Xcel Energy.

Fairhaven Power Company vs. Encana Corporation et al. On Sept. 14, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Fairhaven Power Co. and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs Centerpoint Energy *et al*. and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on December 19, 2005. The plaintiffs subsequently appealed.

Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. On Nov. 29, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Utility Savings and Refund Services LLP and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs. Centerpoint Energy *et al.* and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on December 19, 2005. Plaintiffs subsequently appealed.

Abelman Art Glass vs. Ercana Corporation et al. On Dec. 13, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Abelman Art Glass and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs Centerpoint Energy et al and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on December 19, 2005. Plaintiffs subsequently appealed.

Sinclair Oil Corporation vs. e prime inc and Xcel Energy, Inc. - On July 18, 2005, Sinclair Oil Corporation filed a lawsuit against Xcel Energy and its former subsidiary e prime. In the U.S. District Court for the Northern District of Oklahoma, alleging liability and damages for purported misreporting of price information for natural gas to trade publications in an effort to artificially increase natural gas prices. The complaint also alleges that e prime and Xcel Energy engaged in a conspiracy with other gas sellers to inflate prices through alleged false reporting of gas prices. In response, e prime and Xcel Energy filed a motion with the MDL Panel to have the matter transferred to U.S. District Judge Pro and filed a second motion to dismiss the lawsuit. In response to this motion, this matter has been conditionally transferred to U.S. District Court Judge Pro. Sinclair subsequently filed a motion with the MDL Panel to vacate this transfer. The MDL Panel has yet to issue an order. e prime and Xcel Energy also filed a motion to dismiss with the District Court in Oklahoma based upon the filed rate doctrine. This motion is being held in abeyance pending a ruling from the MDL Panel.

Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al. - On June 21, 2005, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Ever-Bloom, Inc. The lawsuit names as defendants, among others, Xcel Energy and e prime. The lawsuit, filed on behalf of a purported class of gas purchasers, alleges that defendants falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California, purportedly in violation of the Sherman Act. Xcel Energy and e prime intend to vigorously defend themselves against this claim.

Learjet, Inc. vs. e prime and Xcel Energy et al. - On Nov. 4, 2005, a purported class action complaint was filed in state court for Wyandotte County of Kansas on behalf of all natural gas producers in Kansas. The lawsuit alleges that e prime, Xcel Energy and other named defendants conspired to raise the market price of natural gas in Kansas by, among other things, inaccurately reporting price and volume information to the market trade publications. On Dec. 7, 2005, the defendants removed this matter to the U.S. District Court in Kansas. This case is in the early stages; no discovery has been conducted and e prime and Xcel Energy intend to vigorously defend against these claims.

J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al. On Oct. 17, 2005, J.P. Morgan, in its capacity as the liquidating trustee for Farmland Industries Liquidating Trust, filed an amended complaint in Kansas state court adding defendants, including Xcel Energy and e prime, to a previously filed complaint alleging that the defendants inaccurately reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices. The lawsuit was removed to the U.S. District Court in Kansas and subsequently transferred to U.S. District Court Judge Pro, in Nevada pursuant to an order from the MDL Panel. A motion to remand to state court has been filed by plaintiffs and that motion is currently pending. This case is in the early stages, there has been no discovery and e prime and Xcel Energy intend to vigorously defend themselves against these claims.

Payne et al. vs. PSCo et al. - In late October 2003, there was a wildfire in Boulder County, Colo. There was no loss of life, but there was property damage associated with this fire. On Oct. 28, 2005, an action against PSCo related to this fire was filed in Boulder County District Court. There are 28 plaintiffs, including individuals, the City of Jamestown and one private corporation, and three co-defendants, including PSCo. Plaintiffs have asserted that a tree falling into PSCo distribution lines may have caused the fire. This lawsuit is in the early stages and PSCo intends to vigorously defend itself against the claim. This lawsuit is not expected to have a material financial impact and PSCo believes that its insurance coverage will cover any liability in this matter.

Comanche 3 Permit Litigation - On Aug. 4, 2005, CCAP and Clean Energy Action filed suit against the Air Pollution Control Division, Colorado Department of Public Health and Environment in state district court in Pueblo, Colo. The suit alleges the issuance of environmental permits for the proposed Comanche 3 generating station by the Department violates the Colorado Air Pollution Prevention and Control Act. The plaintiffs have sought judicial review of the issuance of the permits. The plaintiffs have not sought a stay of the permits or an injunction on construction pending judicial review. On Aug. 19, 2005, the Colorado attorney general, on behalf of the Department, filed an answer in the suit. On the same date, PSCo filed a motion to intervene and an answer in the suit. On Nov. 20, 2005, the Division submitted the formal record which was entered by the Court. The plaintiff s brief was filed on Feb. 2, 2006, and the government and PSCo will have 60 days to respond.

Fru-Con Construction Corporation vs. Utility Engineering et al. On March 28, 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court for the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con s complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. UE denies this claim and intends to vigorously defend itself. Because this lawsuit was commenced prior to the April 8, 2005, closing of the sale of UE to Zachry Group, Inc., Xcel Energy is obligated to indemnify Zachry up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million. On June 1, 2005, UE filed a motion to dismiss Fru-Con s complaint. A hearing concerning this motion was held on July 18, 2005, with the court taking the matter under advisement. On Aug. 4, 2005, the court granted UE s motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit.

Metropolitan Airports Commission vs. Northern States Power Company On Dec. 30, 2004, the Metropolitan Airports Commission (MAC) filed a complaint in Minnesota state district court asserting that NSP-Minnesota is required to relocate facilities on MAC property at the expense of NSP-Minnesota. MAC claims that approximately $7.1 million charged by NSP-Minnesota over the past five years for relocation costs should be repaid. Both parties have asserted cross motions for partial summary judgment concerning legal obligations associated with rent payments allegedly due and owing by NSP-Minnesota to MAC for the use of its property for a substation that serves the MAC. This hearing was held in January 2006; the judge has not yet issued his decision. Both sides have scheduled depositions of key witnesses to take place in February and March of 2006. Trial has been set for May 2006, additional summary judgment motions are likely prior to trial.

Siewert vs. Xcel Energy Plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minneosta s distribution system. Plaintiffs expert report on the economic damage to their dairy farm states that the total present value of plaintiffs loss is $6.8 million. Trial is scheduled to commence in March 2007. NSP-Minnesota denies these allegations and will vigorously defend itself in this matter.

Other Contingencies

Tax Matters In April 2004, Xcel Energy filed a lawsuit against the government in the U.S. District Court for the District of Minnesota to establish its right to deduct the policy loan interest expense that had accrued during tax years 1993 and 1994 on policy loans related to its company-owned life insurance (COLI) policies that insured certain lives of employees of PSCo. These policies are owned and managed by PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo.

After Xcel Energy filed this suit, the IRS sent it two statutory notices of proposed deficiency of tax, penalty and interest for taxable years 1995 through 1999. Xcel Energy then filed two Tax Court petitions challenging those notices. Xcel Energy anticipates that the dispute relating to its claimed interest expense deductions for tax years 1993 and later will be resolved in the refund suit that is pending in the Minnesota federal district court and that the two Tax Court petitions will be held in abeyance pending the outcome of the refund litigation.

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. The case is expected to proceed to trial and the litigation could take another two or more years.

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 that may be imposed by the IRS, and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. As discussed above, 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. Although the ultimate resolution of this matter is uncertain, it 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, 2005, would reduce retained earnings by an estimated $361 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2005, is approximately $428 million. Xcel Energy annual earnings for 2006 would be reduced by approximately $44 million, after tax, or 10 cents per share, if COLI interest expense deductions were no longer available.

15. Nuclear Obligations

Fuel Disposal NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota s nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE s permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately $12 million in 2005, $13 million in 2004 and $13 million in 2003. In total, NSP-Minnesota had paid approximately $346 million to the DOE through Dec. 31, 2005. However, it is not determinable whether the amount and method of the DOE s assessments to all utilities will be sufficient to fully fund the DOE s permanent storage or disposal facility.

The Nuclear Waste Policy Act required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. In 1996, the DOE notified commercial spent-fuel owners of an anticipated delay in accepting spent nuclear fuel by the required date and conceded that a permanent storage or disposal facility will not be available until at least 2010. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE s failure to meet its statutory and contractual obligations.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and a dry cask facility. With the dry cask storage facility licensed by the NRC, approved in 1994 and again in 2003, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least the end of its license terms in 2013 and 2014. The Monticello nuclear plant has storage capacity in the pool to continue operations until 2010. Storage availability to permit operation beyond these dates is not known at this time. All of the alternatives for spent fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE s uranium-enrichment facilities. In 1993, NSP-Minnesota recorded the DOE s initial assessment of $46 million, which is payable in annual installments from 1993 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2005 was $4.7 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, the unamortized assessment of $8.3 million at Dec. 31, 2005, is deferred as a regulatory asset.

Regulatory Plant Decommissioning Recovery Decommissioning of NSP-Minnesota s nuclear facilities, as last approved by the MPUC, is planned for the period from cessation of operations through 2040, assuming the prompt dismantlement method. NSP-Minnesota is currently accruing the costs for decommissioning over the MPUC-approved cost-recovery period and including the accruals in Accumulated Depreciation. Upon implementation of SFAS No. 143, the decommissioning costs in Accumulated Depreciation and ongoing accruals are reclassified to a regulatory liability account. The total decommissioning cost obligation is recorded as an asset retirement obligation in accordance with SFAS No. 143.

Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are licensed to operate until 2013 and 2014, respectively. In 2003, the Minnesota Legislature changed a law that had limited expansion of on-site storage. On Aug. 25, 2004, the Xcel Energy board of directors authorized the pursuit of renewal of the operating licenses for the Monticello and Prairie Island nuclear plants. NSP-Minnesota filed its application for Monticello with the MPUC in January 2005, seeking a certificate of need for dry spent-fuel storage, and filed an application in March 2005 with the NRC for an operating license extension of up to 20 years. A decision regarding Monticello relicensing is expected in 2007. Plant assessments and other work for the Prairie Island applications are planned in the next two or three years. The Prairie Island license renewal process has not yet begun.

Consistent with cost recovery in utility customer rates, NSP-Minnesota records annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Current authorized funding presumes that costs will escalate in the future at a rate of 4.19 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding. The net unrealized gain on nuclear decommissioning investments is deferred as a Regulatory Liability based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The MPUC last approved NSP-Minnesota s nuclear decommissioning study request in December 2003, using 2002 cost data. In October 2005, NSP-Minnesota filed with the MPUC a nuclear decommissioning study using 2005 cost data. Xcel Energy s recommendation is to reduce the 2006 funding if approved by the MPUC. Xcel Energy expects the MPUC to approve a new funding amount in 2006.

Internal funding for all retail jurisdictions was transferred to the external funds by the end of 2005. Based on the last MPUC approval requiring the acceleration of the internal fund transfer, there is a step change in the level of the overall decommissioning expense at the expiration of the transfer beginning Jan. 1, 2006. Expecting to operate Prairie Island through the end of each unit s licensed life, the approved capital recovery will allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2014. Xcel Energy believes future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2005, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in one to 20 years, and common stock of public companies. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

At Dec. 31, 2005, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $816 million. The following table summarizes the funded status of NSP-Minnesota s decommissioning obligation based on approved regulatory recovery parameters. These amounts are not those recorded in the financial statements for the asset retirement obligation in accordance with SFAS No. 143.

(Thousands of Dollars)	**2005**	**2004**
Estimated decommissioning cost obligation from most recently approved study (2002 dollars)	$ 1,716,618	$ 1,716,618
Effect of escalating costs to 2005 and 2004 dollars (at 4.19 percent per year), respectively	224,946	146,866
Estimated decommissioning cost obligation in current dollars	1,941,564	1,863,484
Effect of escalating costs to payment date (at 4.19 percent per year)	1,851,801	1,929,881
Estimated future decommissioning costs (undiscounted)	3,793,365	3,793,365

Effect of discounting obligation (using risk-free interest rate)	(2,026,003)	(2,139,561)
Discounted decommissioning cost obligation	1,767,362	1,653,804
Assets held in external decommissioning trust	1,047,592	918,442
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 719,770	$ 735,362

Decommissioning expenses recognized include the following components:

(Thousands of Dollars)	2005	2004	2003
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$ 80,582	$ 80,582	$ 80,582
Internally funded (including interest costs)	(57,561)	(53,307)	(35,906)
Interest cost on externally funded decommissioning obligation	(24,516)	(19,026)	(14,952)
Earnings from external trust funds	24,516	19,026	14,952
Net decommissioning accruals recorded	$ 23,021	$ 27,275	$ 44,676

Decommissioning and interest accruals are included with Regulatory Liabilities on the Consolidated Balance Sheets. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the Consolidated Statements of Operations.

Negative accruals for internally funded portions in 2003, 2004 and 2005 reflect the impact of the 2002 decommissioning study, which approved an assumption of 100-percent external funding of future costs. The 2005 nuclear decommissioning filing has not been used for the regulatory presentation because it is effective for 2006. However, the filing and all the updated parameters were used for a new ARO layer for SFAS No. 143 recognition.

16. Regulatory Assets and Liabilities

Xcel Energy s regulated businesses prepare their Consolidated Financial Statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Consolidated Financial Statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy s business that is not regulated cannot use SFAS No. 71 accounting. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of SFAS No. 71 under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in its statement of operations. The components of unamortized regulatory assets and liabilities of continuing operations shown on the balance sheet at Dec. 31 were:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	2005	2004
Regulatory Assets				
Net nuclear asset retirement obligations	1, 15	End of licensed life	$ 282,195	$ 221,864
		Term of related		
Contract valuation adjustments (e)	12	Contract	111,639	102,741
AFDC recorded in plant (a)		Plant lives	170,785	169,352
Losses on reacquired debt	1	Term of related debt	84,290	89,694
Conservation programs (a)		Various	111,429	88,253
Nonnuclear asset retirement obligations	14	Plant lives	32,371	
Nuclear decommissioning costs (b)		Up to two years	8,317	20,494
Employees postretirement benefits other than pension	10	Seven years	27,234	31,125
Renewable resource costs		One to two years	50,453	38,985
		Varies, generally four		

Environmental costs	14, 15	to six years	33,957	28,176
State commission accounting adjustments (a)		Plant lives	14,460	15,945
Plant asset recovery (Pawnee II and Metro Ash)		18 months	7,355	12,258
Unrecovered natural gas costs (c)	1	One to two years	12,998	14,553
Unrecovered electric production and transmission costs (d)	1	To be determined	6,634	
Other		Various	9,286	17,196
Total regulatory assets			$ 963,403	$ 850,636

Regulatory Liabilities			
Plant removal costs	1, 15	$ 895,653	$ 891,018
Pension costs - regulatory differences	10	397,261	377,893
Contract valuation adjustments (e)	12	99,734	56,874
Unrealized gains from decommissioning investments	15	143,396	129,028
Investment tax credit deferrals		84,437	92,227
Deferred income tax adjustments	1	75,171	69,780
Interest on income tax refunds		6,031	9,667
Fuel costs, refunds and other		9,137	4,058
Total regulatory liabilities		$ 1,710,820	$ 1,630,545

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

(b) These costs do not relate to NSP-Minnesota s nuclear plants. They relate to DOE assessments, as discussed previously in Note 15. In 2004, these costs also included unamortized costs for PSCo s Fort St. Vrain nuclear plant decommissioning.

(c) Excludes current portion expected to be returned to customers within 12 months of $16.3 million and $12.4 million for 2005 and 2004, respectively.

(d) In 2004, excluded the current portion expected to be recovered within the next 12 months of $16.1 million.

(e) Includes the fair value of certain long-term contracts used to meet native energy requirements.

17. Segments and Related Information

Xcel Energy has the following reportable segments: Regulated Electric Utility, Regulated Natural Gas Utility and All Other.

Xcel Energy s Regulated Electric Utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, New Mexico, Kansas and Oklahoma. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated Electric Utility also includes commodity trading operations.

Xcel Energy s Regulated Natural Gas Utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

To report income from continuing operations for Regulated Electric and Regulated Natural Gas Utility segments, Xcel Energy must assign or allocate all costs and certain other income. In general, costs are:

- directly assigned wherever applicable;
- allocated based on cost causation allocators wherever applicable; and
- allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1 to the Consolidated Financial Statements. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which are separately determined for each segment. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
2005					
Operating revenues from external customers	$ 7,243,637	$ 2,307,385	$ 74,455	$	$ 9,625,477
Intersegment revenues	767	17,732		(18,499)	
Total revenues	$ 7,244,404	$ 2,325,117	$ 74,455	$ (18,499)	$ 9,625,477
Depreciation and amortization	$ 662,236	$ 89,174	$ 15,911	$	$ 767,321
Financing costs, mainly interest expense	301,185	47,145	108,538	(14,242)	442,626
Income tax expense (benefit)	258,161	32,923	(117,545)		173,539
Income (loss) from continuing operations	$ 440,578	$ 71,213	$ 35,733	$ (48,486)	$ 499,038
2004					
Operating revenues from external customers	$ 6,225,245	$ 1,915,514	$ 74,802	$	$ 8,215,561
Intersegment revenues	1,132	8,735		(9,867)	
Total revenues	$ 6,226,377	$ 1,924,249	$ 74,802	$ (9,867)	$ 8,215,561
Depreciation and amortization	$ 610,127	$ 82,012	$ 13,816	$	$ 705,955
Financing costs, mainly interest expense	299,768	48,757	100,784	(14,829)	434,480
Income tax expense (benefit)	235,743	29,286	(103,094)		161,935
Income (loss) from continuing operations	$ 466,307	$ 86,091	$ 12,173	$ (42,307)	$ 522,264
2003					
Operating revenues from external customers	$ 5,919,938	$ 1,677,768	$ 133,561	$	$ 7,731,267
Intersegment revenues	1,123	10,868		(11,991)	
Total revenues	$ 5,921,061	$ 1,688,636	$ 133,561	$ (11,991)	$ 7,731,267
Depreciation and amortization	$ 625,132	$ 80,688	$ 21,487	$	$ 727,307
Financing costs, mainly interest expense	312,432	57,673	103,825	(22,911)	451,019
Income tax expense (benefit)	239,671	31,314	(100,293)		170,692
Income (loss) from continuing operations	$ 461,363	$ 94,056	$ 4,984	$ (37,579)	$ 522,824

18. Summarized Quarterly Financial Data (Unaudited)

Summarized quarterly unaudited financial data is as follows:

	Quarter ended			
(Thousands of Dollars, except per share amounts)	March 31, 2005 (a)	June 30, 2005 (a)	Sept. 30, 2005 (a)	Dec. 31, 2005 (a)
Revenue	$ 2,381,038	$ 2,073,549	$ 2,288,653	$ 2,882,237
Operating income	279,341	198,098	364,725	250,555
Income from continuing operations	127,643	74,613	197,817	98,964
Discontinued operations - income (loss)	(6,165)	8,793	(1,798)	13,104
Net income	121,478	83,406	196,019	112,068
Earnings available for common shareholders	120,418	82,346	194,959	111,008
Earnings per share from continuing operations - basic	$ 0.32	$ 0.18	$ 0.49	$ 0.25
Earnings per share from continuing operations - diluted	$ 0.31	$ 0.18	$ 0.47	$ 0.24
Earnings (loss) per share from discontinued operations basic	$ (0.02)	$ 0.02	$ (0.01)	$ 0.03
Earnings (loss) per share from discontinued operations diluted	$ (0.02)	$ 0.02	$	$ 0.03
Earnings per share total basic	$ 0.30	$ 0.20	$ 0.48	$ 0.28
Earnings per share total - diluted	$ 0.29	$ 0.20	$ 0.47	$ 0.27

133

	Quarter Ended			
(Thousands of Dollars, except per share amounts)	March 31, 2004 (b)	June 30, 2004 (b)	Sept. 30, 2004 (b)	Dec. 31, 2004 (b)
Revenue	$ 2,248,797	$ 1,760,175	$ 1,974,935	$ 2,231,654
Operating income	321,438	198,694	338,235	217,347
Income from continuing operations	148,684	85,420	165,952	122,208
Discontinued operations income (loss)	1,227	886	(119,232)	(49,184)
Net income	149,911	86,306	46,720	73,024
Earnings available for common shareholders	148,851	85,246	45,660	71,964
Earnings per share from continuing operations basic	$ 0.37	$ 0.21	$ 0.41	$ 0.30
Earnings per share from continuing operations - diluted	$ 0.36	$ 0.21	$ 0.40	$ 0.30
Earnings (loss) per share from discontinued operations basic	$	$	$ (0.30)	$ (0.12)
Earnings (loss) per share from discontinued operations diluted	$	$	$ (0.28)	$ (0.12)
Earnings per share total basic	$ 0.37	$ 0.21	$ 0.11	$ 0.18
Earnings per share total - diluted	$ 0.36	$ 0.21	$ 0.12	$ 0.18

(a) 2005 results include unusual items as follows:

Third-quarter results from continuing operations were decreased by the accrual of legal settlements incurred by the holding company in the amount of $5 million.

Second-quarter results from discontinued operations were increased by $7.7 million due to a true-up on the estimated impairment expected to result from the disposal of Seren, as discussed in Note 2 to the Consolidated Financial Statements.

Fourth-quarter results from discontinued operations include the positive impact of a $17.2 million tax benefit recorded to reflect the final resolution of Xcel Energy s divested interest in NRG.

First quarter revenuehas been reduced by $6.1 million as compared to the amount previously reported in the Quarterly Report filed on Form 10-Q with the SEC for the first quarter of 2005. This adjustment is a result of fees collected from customers on behalf of governmental agencies that were reclassified to be presented net of the related payments made to the agencies.

(b) 2004 results include special charges in the fourth quarter and unusual items as follows:

Fourth quarter results from continuing operations were decreased by the accrual of legal settlements incurred by the holding company in the amount of $17.6 million.

Third-quarter results from discontinued operations were decreased by $112 million, or 27 cents per share, due to the estimated impairment expected to result from the disposal of Seren, as discussed in Note 2 to the Consolidated Financial Statements. During the fourth quarter, an adjustment increasing the impairment by $31 million, or 7 cents per share, was recorded.

Fourth-quarter results from discontinued operations were decreased by $15.7 million, or 4 cents per share, related to a reduction of the NRG tax benefits previously booked, after completion of an NRG tax basis study.

Fourth-quarter results from continuing operations were increased by $33.8 million, or 8 cents per share, due to the accrual of income tax benefits which included $22.3 million related to the successful resolution of various issues and other adjustments to current and deferred taxes.

Fourth-quarter results from continuing operations were decreased by a $19.7 million accrual recorded to reflect SPS best estimate of any potential liability for the impact of its retail fuel cost-recovery proceeding in Texas.

First-quarter revenue has been reduced by $10.4 million as compared to the amount previously reported in the Quarterly Report filed on Form 10-Q with the SEC for the first quarter 2005. Revenue for the quarter ended Dec. 31, 2004 has been reduced by $10.3 million as compared to the amount previously reported in the Annual Report on Form 10-K for 2004. These adjustments are a result of fees collected from customers on behalf of governmental agencies that were reclassified to be presented net of the related payments made to the agencies.

Item 9 Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

During 2004 and 2005, and through the date of this report, there were no disagreements with the independent public accountants on accounting principles or practices, financial statement disclosures, or auditing scope or procedures.

Item 9A Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. As of Dec. 31, 2005, based on an evaluation carried out under the supervision and with the participation of Xcel Energy s management, including the chief executive officer (CEO) and the chief financial officer (CFO), of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy s disclosure controls and procedures are effective.

Internal Controls Over Financial Reporting

No change in Xcel Energy s internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy s internal control over financial reporting.

Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, in general computer activities, and on an entity-wide level. During the fourth quarter and in preparation for issuing its report for the year ended Dec. 31, 2005 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board (PCAOB) and as approved by the SEC and as indicated in Management Report on Internal Controls herein. Xcel Energy has concluded that the internal control over financial reporting was effective.

Item 9B Other Information

Departure of Directors or Principal Officers: Election of Directors; Appointment of Principal Officers

On February 22, 2006, Richard H. Anderson, 50, a member of the Xcel Energy Inc. Board of Directors since May 2004 conveyed to the Governance, Compensation and Nominating Committee of the Board that he did not wish to stand for election by shareholders at the Annual

Meeting of the Company on May 17, 2006. He stated that due to his responsibilities as Executive Vice President of UnitedHealth Group, Inc. (UHG) and Chief Executive Officer of UHG s Ingenix Division, he did not have sufficient time to prepare and participate in the Board and Committee meetings of Xcel Energy. Mr. Anderson will continue to serve as a director until his term expires on May 16, 2006.

PART III

Item 10 Directors and Executive Officers of the Registrant

Information required under this Item with respect to directors is set forth in Xcel Energy s Proxy Statement for its 2006 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 Executive Compensation

Except as set forth below, information required under this Item is set forth in Xcel Energy s Proxy Statement for its 2006 Annual Meeting of Shareholders, which is incorporated by reference.

On Feb. 22, 2006, the Governance, Compensation & Nominating Committee of the Xcel Energy board of directors approved payouts of annual incentive awards for 2005, pursuant to the Xcel Energy Annual Incentive Award Program. Target annual incentive awards, expressed as a percentage of salary, were set by the Committee under the 2000 Annual Incentive Plan at the end of 2004 except for

Mr. Richard C. Kelly as later described.   Payouts of annual incentive awards were dependent on the level of achievement of corporate financial and operational goals and business unit operational goals approved by the Committee, with each individual having the opportunity to earn from 0 percent to approximately 150 percent of his or her target annual incentive award based on the level of achievement in 2005 of the goals applicable to such individual. Corporate goals included targeted earnings per share, a customer satisfaction measurement, an environmental measurement related to air emissions and operations measurements related to generation availability, system availability, a measure of employee engagement and safety. Business unit goals included customer service, reliability, safety, environmental responsibility, reliability, safety and management to budgeted financial results, measured at a business unit level.

Target annual incentive awards (as a percent of base salary) were set for all Xcel Energy officers, ranging from 100 percent of salary for Mr. Brunetti to 55 percent of salary for the other Named Executive Officers. With the approval of the Committee, an award could be multiplied by a leadership rating factor from zero to two. Mr. Kelly s target annual incentive award was set at 70 percent of salary for his time as President and Chief Operating Officer and set at 100 percent of salary for his time as President and Chief Executive Officer.

Payouts of the annual incentive awards for Mr. Brunetti and Mr. Kelly were dependent entirely on attaining corporate goals. For the other Named Executive Officers, the formula was weighted 67 percent to attaining corporate goals and 33 percent to attaining business unit operational goals.

In order to encourage increased share ownership by executive officers, the 2000 Annual Incentive Plan provides the option for executives to receive their payments in shares of common stock or shares of restricted common stock (which vests in equal annual installments over a three-year period) in lieu of cash. A 5 percent premium is added to amounts paid in shares of common stock, and a 20 percent premium is added to amounts paid in shares of restricted common stock.

Based on corporate performance during 2005, payouts under the corporate performance component were 29 percent of the corporate target. Business unit performance resulted in payouts ranging from 23 percent to 53 percent of the target for the business unit goals. As a result, and taking into account adjustments for individual leadership factor ratings the executive officers received from 27 percent to 59 percent of their targeted annual incentive awards. Adjustments for individual leadership factor ratings were not applied to any Named Executive Officers. Based on performance during 2005, the payouts to the Named Executives of Xcel Energy were as follows:

Wayne H. Brunetti	$	292,976
Richard C. Kelly	$	212,966
Gary R. Johnson	$	77,663
Patricia K. Vincent	$	72,948
Benjamin G.S. Fowke III	$	91,866
Paul J. Bonavia	$	82,170

On Feb. 22, 2006, the Governance, Compensation & Nominating Committee of the Xcel Energy board of directors approved payouts of long-term incentive awards pursuant to the Xcel Energy Omnibus Incentive Plan for the three-year measurement cycle that ended in 2005. These performance share awards were granted effective January 1, 2003 for the three-year measurement cycle ended December 31, 2005 and were made in shares, each of which represents the value of one share of Xcel Energy common stock. The target number of shares granted was calculated by dividing the executive s target award by the fair market value of Xcel Energy common stock on the date of the grant. Payout of the performance share award was dependent entirely on a single measure, total shareholder return (TSR) relative to the TSR of a peer group consisting of other companies in the EEI Electrics Index. The performance shares provide for payout at the target level if Xcel Energy s TSR at the end of such three-year period is at the 50th percentile of the peer group and at 200 percent of the target level for performance at or above the 75th percentile of the peer group. The performance shares provide smaller payouts for performance below the 50th percentile. No payout would be made for

performance below the 35^{th} percentile.

For the measurement cycle that ended in 2005 (representing awards granted effective January 1, 2003), the TSR was at 76^{th} percentile resulting in a 200 percent payout. Accordingly, the payouts to the Named Executives of Xcel Energy were as follows:

Wayne H. Brunetti	$ 8,335,999
Richard C. Kelly	$ 2,588,136
Gary R. Johnson	$ 1,509,536
Patricia K. Vincent	$ 1,315,989
Benjamin G.S. Fowke III	$ 424,482
Paul J. Bonavia	$ 1,490,174

Payments to the Named Executive Officers were made in a combination of cash and shares. Mr. Brunetti received $1,000,000 in cash and 384,184 pre-tax shares. Mr. Kelly received $1,000,000 in cash and 83,170 pre-tax shares. Mr. Johnson received $754,768 in cash and 39,527 pre-tax shares. Ms. Vincent received $657,995 in cash and 34,459 pre-tax shares. Mr. Fowke received $212,241 in cash and 11,115 pre-tax shares. Mr. Bonavia received $745,087 in cash and 39,020 pre-tax shares.

Item 12 Security Ownership of Certain Beneficial Owners and Management

Information concerning the security ownership of the directors and officers of Xcel Energy and securities authorized for issuance under equity compensation plans is contained in Xcel Energy s Proxy Statement for its 2006 Annual Meeting of Shareholders which is incorporated by reference.

Item 13 Certain Relationships and Related Transactions

Information concerning relationships and related transactions of the directors and officers of Xcel Energy is contained in Xcel Energy s Proxy Statement for its 2006 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 Principal Accounting Fees and Services

Information concerning fees paid to the principal accountant for each of the last two years is contained in Xcel Energy s Proxy Statement for its 2006 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

Item 15 Exhibits, Financial Statement Schedules

1. Consolidated Financial Statements:
   Management Report on Internal Controls For the year ended Dec. 31, 2005.
   Reports of Independent Registered Public Accounting Firm For the years ended Dec. 31, 2005, 2004 and 2003.
   Consolidated Statements of Operations For the three years ended Dec. 31, 2005, 2004 and 2003.
   Consolidated Statements of Cash Flows For the three years ended Dec. 31, 2005, 2004 and 2003.
   Consolidated Balance Sheets As of Dec. 31, 2005 and 2004.

2. Schedule I Condensed Financial Information of Registrant.
   Schedule II Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2005, 2004 and 2003.

3. Exhibits

   * Indicates incorporation by reference
   \+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy

2.01*	Agreement and Plan of Merger, dated as of March 24, 1999, by and between Northern States Power Co. and New Century Energies, Inc. (Exhibit 2.1 to New Century Energies, Inc. Form 8-K (file no. 001-12907) dated March 24, 1999).
2.02*	Order confirming NRG plan of reorganization dated Nov. 24, 2003 (Exhibit 99.b.10 to Form POS AMC (file no. 070-10152) dated Dec. 1, 2003).
2.03*	Release-Based Amount Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.03 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.04*	Settlement Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.04 to Form 10-K (file no. 001-03034) dated March 15, 2004).

2.05*	Employee Matters Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.05 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.06*	Tax Matters Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.06 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.07*	Stock Purchase Agreement between Xcel Energy Inc., as Seller, and Black Hills Corporation, as Buyer, dated Jan. 13, 2004 (Exhibit 99.01 to Form 8-K (file no. 001-03034) dated May 14, 2004).

Xcel Energy

3.01*	Restated Articles of Incorporation of Xcel Energy (Exhibit 4.01 to Form 8-K (file no. 001-03034) filed Aug. 21, 2000).
3.02*	By-Laws of Xcel Energy (Exhibit 3.01 to Form 10-Q (file no. 001-03034) filed Aug. 4, 2004).

Xcel Energy

4.01*	Trust Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.02*	Supplemental Trust Indenture dated Dec. 15, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee, creating $600 million principal amount of 7 percent Senior Notes, Series due 2010. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.03*	Stockholder Protection Rights Agreement dated Dec. 13, 2000, between Xcel Energy Inc. and Wells Fargo Bank Rights Agent. (Exhibit 1 to Form 8-K (file no. 001-03034) dated Minnesota, N.A., as Jan. 4, 2001).
4.04*	Registration Rights Agreement dated Nov. 21, 2002 by and among Xcel Energy Inc. and Merrill Lynch, Pierce, Fenner & Smith Inc. and Lazard Freres & Co. LLC. (Exhibit 4.125 to Form 10-K (file no. 001-03034) dated March 31, 2003).
4.05*	Redemption Agreement dated Nov. 25, 2002 by and among Xcel Energy Inc. and the Buyers listed on Exhibit A thereto. (Exhibit 4.136 to Form 10-K (file no. 001-03034) dated March 31, 2003).
4.06*	Indenture dated Nov. 21, 2002 between Xcel Energy Inc. and Wells Fargo Bank NA, 7.5 percent convertible senior notes due 2007 (Exhibit 4.137 to Form 10-K (file no. 001-03034) dated March 31, 2003).
4.07*	Supplemental Trust Indenture No. 2 dated June 15, 2003 between Xcel Energy Inc. and Wells Fargo Bank NA, supplementing trust indenture dated Dec. 1, 2000 (Exhibit 4.01 to Form 10-Q (file no. 001-03034) dated Aug. 15, 2003).
4.08*	Indenture dated Nov. 15, 2003 between Xcel Energy Inc. and Wells Fargo Bank Minnesota NA, 7.5 percent convertible senior notes due 2008. (Exhibit 4.10 to Form 10-K (file no. 001-03034), dated March 15, 2004).
4.09*	Registration Rights Agreement dated June 24, 2003 among Xcel Energy Inc. and Credit Suisse First Boston LLC, McDonald Investments Inc. and UBS Securities LLC (Exhibit 4.10 to Form S-4 (file no. 001-03034) dated Oct. 9, 2003).
4.10*	Registration Rights Agreement dated Nov. 21, 2003 among Xcel Energy Inc., Citadel Equity Fund Ltd., Citadel Credit Trading Ltd., and Citadel Jackson Investment Fund Ltd. (Exhibit 4.10 to Form 10-K (file no. 001-03034), dated March 15, 2004)
4.11*	Credit Agreement dated Nov. 4, 2004 between Xcel Energy Inc. and various lenders (Exhibit 10.01 to Form 10-Q (file no. 001-03034) dated Sept. 30, 2004).
4.12*	Amendment to the Credit Agreement Dated Nov. 4, 2004 between Xcel Energy and various lenders (Exhibit 4.01 to Form 10-Q (file no. 001-03034) dated June 30, 2005).
4.13	Amendment to the Credit Agreement Dated Nov. 4, 2004 between Xcel Energy and various lenders dated Oct. 31, 2005.

4.14	Form of Stock Option Agreement Dated Aug. 5, 2005 (Exhibit 4.04 to Form S-8 (file no. 001-03034) dated Aug. 5, 2005.
4.15	Form of Restricted Stock Agreement Dated Aug. 5, 2005 (Exhibit 4.08 to Form S-8 (file no. 001-03034) dated Aug. 5, 2005.
NSP-Minnesota	
4.16*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from Northern States Power Co. (a Minnesota corporation) to Harris Trust and Savings Bank, as Trustee. (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year 1988, file no. 001-03034).
	Supplemental Indentures between NSP-Minnesota and said Trustee, supplemental to Exhibit 4.14, dated as follows:
4.17*	July 1, 1989 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated July 7, 1989).
4.18*	June 1, 1990 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 1, 1990).
4.19*	Oct. 1, 1992 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 13, 1992).

4.20*	April 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 1993).
4.21*	Dec. 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 7, 1993).
4.22*	Feb. 1, 1994 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Feb. 10, 1994).
4.23*	Oct. 1, 1994 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 5, 1994).
4.24*	June 1, 1995 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
4.25*	April 1, 1997 (Exhibit 4.47 to Form 10-K (file no. 001-03034) for the year 1997).
4.26*	March 1, 1998 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
4.27*	May 1, 1999 (Exhibit 4.49 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.28*	June 1, 2000 (Exhibit 4.50 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.29*	Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.30*	June 1, 2002 (Exhibit 4.05 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).
4.31*	June 1, 2002 (Exhibit 4.06 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).
4.32*	Aug. 1, 2002 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 22, 2002).
4.33*	Aug. 1, 2003 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 6, 2003).
4.34*	May 1, 2003 (Exhibit 4.73 to Form 10-K (file no. 000-03034) for the year ended Dec. 31, 2003).
4.35*	July 1, 2005 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).
4.36*	Trust Indenture, dated July 1, 1999, between Northern States Power Co. (a Minnesota corporation) and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.37*	Supplemental Trust Indenture, dated July 15, 1999, between Northern States Power Co. (a Minnesota corporation) and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.38*	Supplemental Trust Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, Northern States Power Co. (a Minnesota corporation) and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.39*	Supplemental Trust Indenture dated June 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.05 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).
4.40*	Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.06 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).
4.41*	Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indenture dated July 1, 1999, between Northern States Power Co. (a Minnesota Corporation) and Wells Fargo Bank Minnesota, National Association, as trustee (Exhibit 4.01 to Form 8-K (file no. 000-31709) dated July 8, 2002).
4.42*	Supplemental Trust Indenture dated Aug. 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 22, 2002).
4.43*	Supplemental Trust Indenture dated Aug. 1, 2003 between Northern States Power Co. (a Minnesota corporation) and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 6, 2003).
4.44*	Supplemental Trust Indenture dated May 1, 2003 between Northern States Power Co. (a Minnesota corporation) and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988.
4.45*	Underwriting Agreement dated July 14, 2005 between NSP-Minnesota, Barclays Capital Inc. and J.P. Morgan Securities Inc., as representatives of the Underwriters named therein, relating to $250,000,000 principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 1.01 to NSP-Minnesota Current Report on Form 8-K, dated July 14, 2005).
4.46*	$375,000,000 Credit Agreement among Northern States Power Company, as Borrower, the several lenders from time to time parties hereto, The Bank of Tokyo-Mitsubishi, LTD., Chicago Branch and CITIBANK, N.A., as documentation agents, The Bank of New York and Wells Fargo Bank, National Association, as Syndication Agents, and JPMorgan Chase Bank, N.A., as administrative agent, dated as of April 21, 2005 (Exhibit 4.01 to Xcel Energy Form 10-Q for the quarter ended March 31, 2005 (file number 001-03034)).
4.47*	Supplemental Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250,000,000 principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, dated July 14, 2005).
4.48	Amendment to the Credit Agreement dated April 21, 2005 between Northern States Power Company and various lenders dated Oct. 31, 2005.

NSP-Wisconsin

4.49*	Supplemental and Restated Trust Indenture, dated March 1, 1991. (Exhibit 4.01K to Registration Statement 33-39831).
4.50*	Supplemental Trust Indenture, dated April 1, 1991. (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).
4.51*	Supplemental Trust Indenture, dated March 1, 1993. (Exhibit to Form 8-K (file no. 001-03140) dated March 3, 1993).
4.52*	Supplemental Trust Indenture, dated Oct. 1, 1993. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 21, 1993).
4.53*	Supplemental Trust Indenture, dated Dec. 1, 1996. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).
4.54*	Trust Indenture dated Sept. 1, 2000, between Northern States Power Co. (a Wisconsin corporation) and Firstar Bank, N.A. as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
4.55*	Supplemental Trust Indenture dated Sept. 15, 2000, between Northern States Power Co. (a Wisconsin corporation) and Firstar Bank, N.A. as Trustee, creating $80 million principal amount of 7.64 percent Senior Notes, Series due 2008. (Exhibit 4.02 to Form 8-K (file no 001-03140) dated Sept. 25, 2000).
4.56*	Supplemental Trust Indenture dated Sept. 1, 2003 between Northern States Power Co. (a Wisconsin corporation) and US Bank NA, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.57*	Exchange and Registration Rights Agreement dated Oct. 2, 2003 among Northern States Power Co. (a Wisconsin corporation) and Goldman, Sachs & Co. and BNY Capital Markets, Inc. (Exhibit 4.92 to Xcel Energy Form 10-K (file no. 001-03034), dated March 15, 2004)

PSCo

4.58*	Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 Exhibit 4(a)).
4.59*	Indentures supplemental to Indenture dated as of Oct. 1, 1993:

Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.	Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)	Aug. 15, 2002	10-Q, Sept. 30, 2002	4.03
Jan. 1, 1994	10-K, 1993	4(b)(3)	Sept. 1, 2002	8-K, Sept. 18, 2002	4.01
Sept. 2, 1994	8-K, September 1994	4(b)	Sept. 15, 2002	10-Q, Sept. 30, 2002	4.04
May 1, 1996	10-Q, June 30, 1996	4(b)	March 1, 2003	S-3, April 14, 2003 (333-104504)	4(b)(3)
Nov. 1, 1996	10-K, 1996	4(b)(3)	April 1, 2003	10-Q May 15, 2003 (001-03034)	4.02
Feb. 1, 1997	10-Q, March 31, 1997	4(b)	May 1, 2003	S-4, June 11, 2003 (333-106011)	4.9
April 1, 1998	10-Q, March 31,1998	4(b)	Sept. 1, 2003	8-K, Sept. 2, 2003 (001-03280)	4.02
			Sept. 15, 2003	Xcel 10-K, Mar. 15, 2004 (001-03034)	4.100
			Aug. 1, 2005	PSCo 8-K, Aug. 18, 2005 (001-03280)	4.02

4.60* Indenture dated July 1, 1999, between Public Service Co. of Colorado and The Bank of New York, providing for the issuance of Senior Debt Securities and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).

4.61*	Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129,500,000 Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A. (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file number 001-3280).
4.62*	Registration Rights Agreement dated March 14, 2003 among Public Service Co. of Colorado , Bank One Capital Markets, Inc. and UBS Warburg LLC (Exhibit 4.1 to Form S-4 (file no. 333-106011) dated June 11, 2003).

4.63*	$500,000,000 Credit Agreement among Public Service Company of Colorado, as Borrower, the several lenders from time to time parties hereto, Keybank National Association and USB Loan Finance LLC, as documentation agents, The Bank of New York and Wells Fargo Bank, National Association, as syndication agents and JPMorgan Chase Bank, N.A., as administrative agent dated as of April 21, 2005 (Exhibit 4.02 to Form 10-Q (file no. 001-03034) dated March 31, 2005).
4.64	$50,000,000.00 Revolving Line of Credit Note between Public Service Company of Colorado and Wells Fargo Bank, National Association, as of December 1, 2005.
4.65	Amendment to the Credit Agreement dated April 21, 2005 between Public Service Company of Colorado and various lenders dated Oct. 31, 2005.
SPS	
4.66*	Indenture dated Feb. 1, 1999 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.67*	First Supplemental Indenture dated March 1, 1999 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 99.3 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.68*	Second Supplemental Indenture dated Oct. 1, 2001 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 23, 2001).
4.69*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between Southwestern Public Service Co. and JPMorgan Chase Bank, as successor trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.70*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 -Exhibit 4(b)).
4.71*	$250,000,000 Credit Agreement among Southwestern Public Service Company, as Borrower, the several lenders from time to time parties hereto, Barclays Bank PLC and Harris Nexbitt Financing, INC., as documentation agents, The Bank of New York and Wells Fargo Bank, National Association, as syndication agents, and JPMorgan Chase Bank, N.A., as administrative agent dated as of April 21, 2005 (Exhibit 4.03 to Form 10-Q (file no. 001-03034) dated March 31, 2005).
4.72*	Registration Rights Agreement dated Oct. 6, 2003 among Southwestern Public Service Co., Citigroup Global Markets Inc. and Credit Suisse First Boston LLC.
Xcel Energy	
10.01* +	Xcel Energy Omnibus Incentive Plan (Exhibit A to Form DEF-14A (file no. 001-03034) filed Aug. 29, 2000).
10.02* +	Xcel Energy Executive Annual Incentive Award Plan (Exhibit B to Form DEF-14A (file no. 001-03034) filed Aug. 29, 2000).
10.03* +	Employment Agreement dated March 24, 1999, among Northern States Power Co. (a Minnesota corporation), New Century Energies, Inc. and Wayne H. Brunetti (Exhibit 10(b) to New Century Energies, Inc. Form 10-Q, (file no. 001-12927) dated March 31, 1999).
10.04* +	Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to NSP-Minnesota Form 10-Q (file no. 001-03034) for the quarter ended March 31, 1998).
10.05* +	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy As Amended and Restated Effective Oct. 1, 1997. (Exhibit 10.15 to NSP-Minnesota Form 10-K (file no. 001-03034) for the year 1997).
10.06* +	Senior Executive Severance Policy, effective March 24, 1999, between New Century Energies, Inc. and Senior Executives (Exhibit 10(a)(2) to New Century Energies, Inc. Form 10-Q, (file no. 001-12927) dated March 31, 1999).
10.07* +	New Century Energies Omnibus Incentive Plan, (Exhibit A to New Century Energies, Inc. Form DEF 14A (file no. 001-12927) filed March 26, 1998.
10.08* +	

	Directors Voluntary Deferral Plan (Exhibit 10(d) (1) to New Century Energies, Inc. Form 10-K (file no. 001-12927) dated Dec 31, 1998).
10.09* +	Supplemental Executive Retirement Plan (Exhibit 10(e) (1) to New Century Energies, Inc. Form 10-K (file no. 001-12927) dated Dec. 31, 1998).
10.10* +	Salary Deferral and Supplemental Savings Plan for Executive Officers (Exhibit 10(f) (1) to New Century Energies, Inc. Form 10-K (file no. 001-12927) dated Dec. 31, 1998).
10.11* +	Salary Deferral and Supplemental Savings Plan for Key Managers (Exhibit 10(g) (1) to New Century Energies, Inc. Form 10-K (file no. 001-12927) dated Dec. 31, 1998).
10.12* +	Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (Exhibit 10(e)(2) to PSCo Form 10-K (file no. 001-3280) dated Dec. 31, 1991).
10.13* +	Form of Key Executive Severance Agreement, as amended on Aug. 22, and Nov. 27, 1995. (Exhibit 10(e)(4) to PSCo Form 10-K (file no. 001-3280) dated Dec. 31, 1995).

10.14* +	Supplemental Retirement Income Plan as amended July 23, 1991 (Exhibit 10(d) to SPS Form 10-K, (file no. 001-03789) dated Aug. 31, 1996).
10.15* +	Xcel Energy Senior Executive Severance and Change-in-Control Policy dated Oct. 22, 2003 (Exhibit 10.10 to SPS Form S-4, (file no. 333-112032) dated Jan. 21, 2004).
10.16* +	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated Jan. 1, 2004 (Exhibit B to Form DEF-14A (file no. 001-03034) dated Apr. 9, 2004).
10.17* +	Xcel Energy Nonqualified Deferred Compensation Plan (2002 restatement) (Exhibit 10.23 to Xcel Energy Form 10-K (file no. 001-03034) dated March 15, 2004).
10.18* +	Xcel Energy Non-employee Directors Deferred Compensation Plan (Exhibit 10.24 to Xcel Energy Form 10-K (file no. 001-03034) dated March 15, 2004).
10.19* +	Xcel Energy 401(k) Savings Plan, amended and restated as of Jan. 1, 2002 (Exhibit 10.19 to SPS Form S-4 (file no. 333-112032) dated Jan. 21, 2004).
10.20* +	New Century Energies, Inc. Employee Investment Plan for Bargaining Unit Employees and Former Non-bargaining Unit Employees, as amended and restated effective Jan. 1, 2004 but with certain retroactive amendments (Exhibit 10.20 to SPS Form S-4 (file no. 333-112032) dated Jan. 21, 2004).
10.21*	Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.22*	Securities Litigation Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.23*	ERISA Actions Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.02 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.24*	Shareholder Derivative Action Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.03 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.25* +	Employment Agreement, effective Dec. 15, 1997, between company and Mr. Paul J. Bonavia, as amended (Exhibit 10.25 to Xcel Energy Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2004).
10.26* +	Compensation and reimbursement practices for Xcel Energy non-employee directors (Exhibit 10.01 to Xcel Energy Form 10-Q (file no. 001-03034) dated Sept. 30, 2005.
10.27* +	Xcel Energy executive officer salaries, annual bonus targets and long-term compensation awards for 2005 (Exhibit 10.27 to Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2004).
10.28* +	Amended Schedule of Participants for Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.28 to Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2004).
10.29* +	Xcel Energy Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.06 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.30* +	Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.31* +	Xcel Energy Omnibus Incentive Plan Form of Performance Share Agreement (Exhibit 10.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.32* +	Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.07 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.33* +	Xcel Energy Omnibus 2005 Incentive Plan (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated May 25, 2005).
10.34* +	Xcel Energy Executive Annual Incentive Award Plan (Exhibit 10.02 to Form 8-K (file no. 001-03034) dated May 25, 2005).
10.35* +	Xcel Energy Amended Employment Agreement, dated as of June 29, 2005, by and between Xcel Energy Inc., a Minnesota corporation, and Wayne H. Brunetti (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated June 29, 2005).
10.36* +	Xcel Energy Supplemental Executive Retirement Plan (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated Dec. 13, 2005).
10.37 +	Xcel Energy executive officer salaries, annual bonus targets and long-term compensation awards for 2006

10.38 +	Amended Schedule of Participants for Xcel Energy Senior Executive Severance and Change-in-Control Policy
NSP-Minnesota	
10.39*	Facilities Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (kv) line.v (Exhibit 5.06I to file no. 2-54310).
10.40*	Transactions Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06J to file no. 2-54310).
10.41*	Coordinating Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06K to file no. 2-54310).

10.42*	Ownership and Operating Agreement, dated March 11, 1982, between Northern States Power Co. (a Minnesota corporation), Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.43*	Power Agreement, dated June 14, 1984, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.44*	Power Agreement, dated August 1988, between Northern States Power Co. (a Minnesota corporation) and Minnkota Power Co. (Exhibit 10.08 to Form 10-K for the year 1988, file no. 001-03034).
10.45*	Assignment and Assumption Agreement, dated Aug. 18, 2000 between Northern States Power Co. (a Minnesota corporation) and Xcel Energy Inc. (Exhibit 10.08 to Form 10 of NSP-Minnesota, file no. 000-31709).
10.46*	Amended agreement for the sale of thermal energy dated Jan. 1, 1983 between NRG Energy (formerly known as Norenco Corp.) and Northern States Power Co. (a Minnesota corporation) and Norenco Corp. (Exhibit 10.33 to NRG s Registration on Form S-1, file no. 333-35096).
10.47*	Operations and maintenance agreement dated Nov. 1, 1996 between NRG Energy and Northern States Power Co. (a Minnesota corporation). (Exhibit 10.34 to NRG s Registration on Form S-1, file no. 333-35096).
10.48*	Amended Agreement for the sale of thermal energy and wood byproduct dated Dec. 1, 1986 between Northern States Power Co. (a Minnesota corporation) and Norenco Corp. (Exhibit 10.36 to NRG s Registration on Form S-1, file no. 333-35096).
10.49*	Restated Interchange Agreement dated Jan. 16, 2001 between Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.50*	500 megawatt System Participation Power Sale Agreement dated July 30, 2002 between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board (Exhibit 99.01 to NSP-Minnesota Form 8-K (file no.001-31387) dated March 25, 2003).
NSP-Wisconsin	
10.51*	Restated Interchange Agreement dated Jan. 16, 2001 between Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
PSCo	
10.52*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between Public Service Co. of Colorado and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 Exhibit 10(c)(1)).
10.53*	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between Public Service Co. of Colorado and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 Exhibit 10(c)(2)).
10.54*	Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.55*	Settlement Agreement among Public Service Co. of Colorado and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
SPS	
10.56*	Coal Supply Agreement (Harrington Station) between Southwestern Public Service Co. and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979

	Exhibit 3).
10.57*	Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K, (file no. 001-03789) May 14, 1979 Exhibit 5(A)).
10.58*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K, (file no. 3789) May 14, 1979 Exhibit 5(B)).
10.59*	Coal Supply Agreement (Tolk Station) between Southwestern Public Service Co. and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 Exhibit 10(b)).
10.60*	Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 Exhibit 10(c)).
10.61*	Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and Southwestern Public Service Co.

Xcel Energy

12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm.
24.01	Written Consent Resolution of the Board of Directors of Xcel Energy Inc., adopting Power of Attorney
31.01	Principal Executive Officer s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.

SCHEDULE I

CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

STATEMENTS OF OPERATIONS

	Year ended Dec. 31, 2005	2004 (Thousands of Dollars)	2003
Income:			
Equity in income of subsidiaries	$ 547,524	$ 564,572	$ 560,062
Total income	547,524	564,572	560,062
Expenses and other deductions:			
Operating expenses	9,151	27,588	22,004
Other (income) expense	(6,047)	(4,800)	(8,292)
Interest charges and financing costs	87,804	74,608	73,444
Total expenses and other deductions	90,908	97,396	87,156
Income from continuing operations before taxes	456,616	467,176	472,906
Income taxes (benefit)	(42,422)	(55,088)	(49,918)
Income from continuing operations	499,038	522,264	522,824
Income from discontinued operations, net of tax	13,934	(166,303)	99,568
Net income (loss)	512,972	355,961	622,392
Preferred dividend requirements	4,241	4,241	4,241
Earnings available to common	$ 508,731	$ 351,720	$ 618,151

See Xcel Energy Inc. Notes to Consolidated Financial Statements in Part II, Item 8.

CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

STATEMENTS OF CASH FLOWS

(Thousands of Dollars)

	Years Ended Dec. 31		
	2005	**2004**	**2003**
OPERATING ACTIVITIES:			
Net cash (used in) provided by operating activities	$ 391,776	$ (19,607)	$ 772,709
INVESTING ACTIVITIES:			
Return of capital from subsidiaries	62,417	66,068	
Capital contributions to subsidiaries	(504,402)	(367,763)	(186,272)
Restricted cash		37,213	(37,213)
Investing cash flows provided by (used in) discontinued operations	199,961	252,557	79,637
Net cash used in investing activities	(242,024)	(11,925)	(143,848)
FINANCING ACTIVITIES:			
Short-term borrowings net	325,516		(399,000)
Proceeds from issuance of long-term debt	484,824	420,616	250,348
Repayment of long-term debt	(625,000)	(281,000)	
Proceeds from issuance of common stock	9,085	6,985	3,219
Common stock repurchase		(32,023)	
Dividends paid	(343,092)	(320,444)	(303,316)
Financing cash flows related to discontinued operations			
Net cash (used in) provided by financing activities	(148,667)	(205,866)	(448,749)
Net increase (decrease) in cash and cash equivalents	1,085	(237,398)	180,112
Cash and cash equivalents at beginning of year	82	237,480	57,368
Cash and cash equivalents at end of year	$ 1,167	$ 82	$ 237,480

See Xcel Energy Inc. Notes to Consolidated Financial Statements in Part II, Item 8.

CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

BALANCE SHEETS

(Thousands of Dollars)

	2005	2004
Assets		
Cash and cash equivalents	$ 1,167	$ 82
Restricted cash		
Accounts receivable from subsidiaries	214,271	256,615
Current assets related to discontinued operations		
Other current assets	30,542	34,800
Total Current Assets	245,980	291,497
Investment in subsidiaries	6,644,114	5,945,715
Other assets	76,067	74,943
Noncurrent assets related to discontinued operations	80,101	349,155
Total Other Assets	6,800,282	6,369,813
Total Assets	**$ 7,046,262**	**$ 6,661,310**
Liabilities and Equity		
Current liabilities related to discontinued operations	$ 10,128	$ 8,701
Dividends payable	87,788	83,405
Short Term Debt	325,516	
Other current liabilities	16,741	29,795
Total Current Liabilities	440,173	121,901
Other liabilities	42,123	23,880
Total Other Liabilities	42,123	23,880
Long-term debt	1,063,731	1,207,631
Preferred stockholders equity	104,980	104,980
Common stockholders equity	5,395,255	5,202,918
Total Capitalization	6,563,966	6,515,529
Total Liabilities and Equity	**$ 7,046,262**	**$ 6,661,310**

See Xcel Energy Inc. Notes to Consolidated Financial Statements in Part II, Item 8.

CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND OTHER COMPREHENSIVE INCOME

Incorporated by reference is Xcel Energy Inc. and Subsidiaries Consolidated Statements of Common Stockholders Equity and Other Comprehensive Income in Part II, Item 8.

See Xcel Energy Inc. Notes to Consolidated Financial Statements in Part II, Item 8.

SCHEDULE II

XCEL ENERGY INC.

AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

Years Ended Dec. 31, 2005, 2004 and 2003

(Thousands of Dollars)

		Additions			
	Balance at beginning of period	Charged to costs & expenses	Charged to other accounts (1)	Deductions from reserves (2)	Balance at end of period
Reserve deducted from related assets:					
Provision for uncollectible accounts:					
2005	$ 34,299	$ 43,327	$ 12,379	$ 50,207	$ 39,798
2004	$ 30,727	$ 33,831	$ 11,095	$ 41,354	$ 34,299
2003	$ 23,702	$ 35,234	$ 14,568	$ 42,777	$ 30,727

(1) Recovery of amounts previously written off.

(2) Principally uncollectible accounts written off or transferred.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Xcel Energy Inc.

February 24, 2006

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

/s/ RICHARD C. KELLY
Richard C. Kelly
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ TERESA S. MADDEN
Teresa S. Madden
Vice President and Controller
(Principal Accounting Officer)

*
Richard H. Anderson
Director

*
C. Coney Burgess
Director

*
Roger R. Hemminghaus
Director

*
A. Barry Hirschfeld
Director

*
Douglas W. Leatherdale
Director

*
Albert F. Moreno
Director

*
Margaret R. Preska
Director

*
A. Patricia Sampson
Director

*
Richard H. Truly
Director

* /s/ TERESA S. MADDEN
Teresa S. Madden
Attorney-in-Fact

150