UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015
or

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

Commission File Number: 001-3034

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

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

414 Nicollet Mall
Minneapolis, MN 55401
(Address of principal executive offices)
Registrant's telephone number, including area code: **612-330-5500**

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $2.50 par value per share	New York Stock Exchange

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

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

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

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

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

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

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

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

As of June 30, 2015, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $16,313,953,331 and there were 506,959,395 shares of common stock outstanding.

As of February 15, 2016, there were 507,553,673 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2016 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Eloigne	Eloigne Company
NCE	New Century Energies, Inc.
NMC	Nuclear Management Company, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
PSRI	P.S.R. Investments, Inc.
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries
XETD	Xcel Energy Transmission Development Company, LLC
XEST	Xcel Energy Southwest Transmission Company, LLC
XEWT	Xcel Energy West Transmission Company, LLC

Federal and State Regulatory Agencies

ASLB	Atomic Safety and Licensing Board
CFTC	Commodity Futures Trading Commission
CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
PNM	Public Service Company of New Mexico
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider (recovers the costs associated with investments in environmental improvements to fossil fuel generation plants)
EPU	Extended power uprate
ERP	Electric resource plan
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor (recovers the costs of certain purchased power costs)
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
QSP	Quality of service plan
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard (recovers the costs of new renewable generation)
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
ATM	At-the-market
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAA	Clean Air Act
CACJA	Clean Air Clean Jobs Act
CAIR	Clean Air Interstate Rule
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCN	Certificate of convenience and necessity
CIG	Colorado Interstate Gas Company, LLC
CO_2	Carbon dioxide

CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
EEI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share
ERCOT	Electric Reliability Council of Texas
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FIP	Federal implementation plan
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
HTY	Historic test year
IM	Integrated market
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
MYP	Multi-year plan
NAAQS	National Ambient Air Quality Standard
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NOL	Net operating loss
NOx	Nitrogen oxide
NOV	Notice of violation
NTC	Notifications to construct
NYISO	New York Independent System Operator
O&M	Operating and maintenance
OCC	Office of Consumer Counsel
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
PV	Photovoltaic
QF	Qualifying facilities
R&E	Research and experimentation
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity

RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
Sharyland	Sharyland Distribution and Transmission Services, LLC
SIP	State implementation plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
S&P	Standard & Poor's Ratings Services
TO	Transmission owner
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
Wexpro	Wexpro Development Company

Measurements

Bcf	Billion cubic feet
GWh	Gigawatt hours
KV	Kilovolts
KWh	Kilowatt hours
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2015, Xcel Energy Inc.'s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, and serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

Xcel Energy Inc. was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The public may read and copy any materials that Xcel Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

Xcel Energy's corporate strategy focuses on four core objectives: improving utility performance; driving operational excellence; improving customer experience; and investing for the future. These core objectives are designed to provide an attractive total return to our investors, including long-term annual ongoing EPS growth of four to six percent and annual dividend increases of five to seven percent.

NSP-Minnesota

NSP-Minnesota is a utility primarily 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 eight percent of its total KWh sold in 2015. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 88 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2015. Although NSP-Minnesota's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large C&I electric sales include the following industries: petroleum, coal and food products. For small C&I customers, significant electric retail sales include the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System.

NSP-Minnesota owns the following direct subsidiary: United Power and Land Company, which holds real estate.

NSP-Wisconsin

NSP-Wisconsin is a utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in this service territory. NSP-Wisconsin provides electric utility service to approximately 256,000 customers and natural gas utility service to approximately 112,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2015. Although NSP-Wisconsin's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Wisconsin's large C&I electric sales include the following industries: food products, paper, allied products and sand mining for oil and gas extraction. For small C&I customers, significant electric retail sales include the following industries: grocery and dining establishments, educational services and health services. Generally, NSP-Wisconsin's earnings contribute approximately five percent to 10 percent of Xcel Energy's consolidated net income.

The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota.

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 is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 11 percent of its total KWh sold in 2015. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.4 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2015. Although PSCo's large C&I electric retail customers are comprised of many diversified industries, a significant portion of PSCo's large C&I electric sales include the following industries: fabricated metal products, communications and business services. For small C&I customers, significant electric retail sales include the following industries: real estate and dining establishments. Generally, PSCo's earnings contribute approximately 40 percent to 50 percent of Xcel Energy's consolidated net income.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc. and United Water Company, both of which own certain real estate interests; and Green and Clear Lakes Company, which owns water rights and certain real estate interests. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

SPS

SPS is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 31 percent of its total KWh sold in 2015. SPS provides electric utility service to approximately 389,000 retail customers in Texas and New Mexico. Approximately 71 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2015. Although SPS' large C&I electric retail customers are comprised of many diversified industries, a significant portion of SPS' large C&I electric sales include the following industries: oil and gas extraction, as well as petroleum and coal products. For small C&I customers, significant electric retail sales include the following industries: oil and gas extraction, grocery and dining establishments. Generally, SPS' earnings contribute approximately 10 percent to 15 percent of Xcel Energy's consolidated net income.

Other Subsidiaries

WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to Cheyenne, Wyo.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. The gas pipeline and storage facilities are leased under a FERC-approved agreement to CIG.

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

XETD and XEST are transmission-only subsidiaries that will, respectively, participate in MISO and SPP competitive bidding processes for transmission projects. XEWT is a transmission-only subsidiary formed to competitively bid on transmission projects in the western United States.

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

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 17 to the consolidated financial statements for further discussion relating to comparative segment revenues, income from operations and related financial information.

ELECTRIC UTILITY OPERATIONS

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's ERPs for meeting customers' future energy needs. The MPUC also certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. As approved by the FERC, NSP-Minnesota operates within the MISO RTO and MISO wholesale market. NSP-Minnesota is authorized to make wholesale electric sales at market-based prices. NSP-Minnesota is a transmission owning member of the MISO RTO.

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

- *CIP* — The CIP recovers the costs of conservation and demand-side management programs that help customers save energy.
- *EIR* — The EIR recovers the costs of environmental improvement projects.
- *RDF* — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — The RES recovers the cost of new renewable generation in Minnesota.
- *RER* — The RER recovers the cost of new renewable generation in North Dakota.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in electric transmission and distribution costs that facilitate grid modernization.
- *Infrastructure* — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred costs of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or base rates.

Minnesota state law requires NSP-Minnesota to invest two percent of its state electric revenues and half a percent of its state gas revenues in CIP. NSP-Minnesota was in compliance with this standard in 2015 and expects to be in compliance in 2016. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures. Minnesota state law also requires NSP-Minnesota to submit a CIP plan at least every three years.

CIP Triennial Plan — In 2012, the DOC approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the energy savings goals and budgets over the previous plan. The plan sets an annual energy savings goal for electric of saving the equivalent of 1.5 percent the volume of electric energy sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent the volume of gas energy sales. During 2015, NSP-Minnesota submitted an extension to the triennial plan for 2016 which was approved by the DOC. NSP-Minnesota anticipates submitting a 2017 through 2019 plan during the first half of 2016.

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 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
NSP System	9,524	8,848	8,621	9,327

The peak demand for the NSP System typically occurs in the summer. The 2015 system peak demand for the NSP System occurred on Aug. 14, 2015. The 2015 system peak demand was lower due to cooler summer weather. The 2016 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Generally, long-term dispatchable purchased power contracts typically require a periodic payment to secure the capacity and a charge for the delivered associated energy. Long-term energy-only purchased power contracts contain a charge for the purchased energy. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Courtenay Wind Farm — In September 2015, NSP-Minnesota began construction of the Courtenay wind farm, a 200 MW NSP-Minnesota owned project in North Dakota. In July and August 2015, the MPUC and NDPSC, respectively, approved the Courtenay wind farm with recovery up to $300 million of capital costs. The project costs were included in the Minnesota RES rider and the North Dakota RER.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Integrated Resource Plan (the Plan) with the MPUC.

In October 2015, NSP-Minnesota proposed revisions to the Plan. The revised proposal addressed stakeholder recommendations as well as the final Clean Power Plan (CPP) issued by the EPA. The revised Plan is based on four primary elements: (1) accelerate the transition from coal energy to renewables, (2) preserve regional system reliability, (3) pursue energy efficiency gains and grid modernization, and (4) ensure customer benefits. The provisions included in the Plan would allow for a 60 percent reduction in carbon emissions from 2005 levels by 2030 and is expected to result in 63 percent of NSP System energy being carbon-free by 2030. Specific terms of the proposal include:

- The addition of 800 MW of wind and 400 MW of utility scale solar to the pre-2020 time-frame;
- The addition of 1000 MW of wind and 1000 MW of utility scale solar between 2020-2030;
- The retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026;
- The addition of a 230 MW natural gas combustion turbine in North Dakota by 2025;
- Replacement of Sherco coal generation with a 786 MW natural gas combined cycle unit at the Sherco site no later than 2026; and
- Operation of the Monticello and PI nuclear plants through their current license periods in the early 2030's.

NSP-Minnesota believes this will provide substantial opportunities for the ownership of renewable generation and replacement thermal generation. In January 2016, NSP-Minnesota filed supplemental economic and technical information in support of its revised Plan, demonstrating anticipated compliance with the CPP while maintaining reasonable costs for customers. Additionally, NSP-Minnesota responded to MPUC inquiries regarding forecasted cost increases at PI (through end of licensed life) and committed to provide additional information if the MPUC wishes to further explore alternatives to operating PI through its current licenses. While the procedural schedule has not yet been finalized, the current expectation is that the MPUC will make a decision in the second half of 2016.

North Dakota Energy Resource Considerations **—** In February 2014, the NDPSC approved a settlement agreement between NSP-Minnesota and NDPSC Advocacy Staff in resolution of the 2013 North Dakota electric rate case. Among other things, the settlement agreement included a commitment to develop a generation cost allocation mechanism for serving North Dakota customers in a way that reflects North Dakota energy policy. In September 2015, NSP-Minnesota and NDPSC Advocacy Staff satisfied this commitment through joint filing of a Negotiated Agreement with key terms including:

- Acceleration of NSP-Minnesota’s commitment to locate thermal generation in North Dakota from 2036 to by the end of 2025;
- Exclusion of select wind and small solar PPAs from the NSP-Minnesota’s North Dakota Fuel Cost Rider;
- Continued recovery in North Dakota of six existing biomass PPAs, subject, in part, to refund if NSP-Minnesota fails to achieve its generation commitment by the end of 2025;
- Extension of the current rate moratorium through 2017;
- NDPSC Staff support for continued use of 12-Coincident Peak system allocator through 2025; and,
- Development of a framework to address future generation resources to be filed with the NDPSC by Jan. 1, 2017.

The NDPSC conducted a work session in February 2016, to discuss their view of the Negotiated Agreement with their Advisory Staff. Next steps would include further NDPSC hearing(s) to continue discussion or take action on the Negotiated Agreement. No specific procedural schedule has been established for this matter.

NSP-Minnesota’s Petition for an Advance Determination of Prudence **—** In February 2016, the NDPSC discussed NSP-Minnesota’s Petition for an Advance Determination of Prudence (ADP) for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation. While a certain commissioner indicated support for the opportunity to add larger, low-priced, dispatchable generation, other commissioners were concerned the resource would not be necessary by the 2019 expected in-service date and not supportive of the ADP. Commissioners are expected to vote on the matter on March 9, 2016. The North Dakota portion of the PPA is approximately $1.2 million per year.

CapX2020 **—** The estimated cost of the five major CapX2020 transmission projects listed below is $2 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total investment. As of Dec. 31, 2015, Xcel Energy has invested $1.0 billion of its $1.1 billion share of the five CapX2020 transmission projects. The projects are as follows:

- Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 161/345 Kilovolt (KV) transmission line — The Wisconsin portion of the project includes a new substation and approximately 50 miles of new 345 KV transmission line, at an estimated cost of $211 million. The final 161 KV segment of the project went into service in January 2016, while the final 345 KV segment of the project is expected to go into service in the fall of 2016;
- Brookings County, S.D. to Hampton, Minn. 345 KV transmission line — The project was placed in service in March 2015;
- Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line — The project was placed in service in September 2012;
- Monticello, Minn. to Fargo, N.D. 345 KV transmission line — In April 2015, the final portion of the project was placed in service; and
- Big Stone South to Brookings County, S.D. 345 KV transmission line — Construction on the line began in September 2015, with completion anticipated in 2017.

Minnesota Solar **—** Minnesota legislation requires 1.5 percent of a public utility's total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized 20 kilowatts or less. NSP-Minnesota anticipates it will meet its compliance requirements through large and small scale solar additions.

NSP-Minnesota also offers customer solar programs: a solar production incentive program for rooftop solar, called Solar*Rewards®, and a community solar garden program that provides bill credits to participating subscribers, called Solar*Rewards® Community®. Additionally, the DOC offers the "Made in Minnesota" program, providing incentives for the installation of small solar systems that were manufactured in-state, which generates renewable energy credits for utilities including NSP-Minnesota.

In August 2015, the MPUC issued an order regarding the Solar*Rewards Community program, limiting the size of solar installations eligible to participate in the program to five MW or less through Sept. 25, 2015. Subsequently, projects must be one MW or less. In October 2015, the MPUC denied requests for reconsideration of the project size limitation. Sunrise Energy Ventures, a Solar*Rewards Community developer, has appealed this decision to the Minnesota Court of Appeals.

Minnesota Legislation **—** In June 2015, the Minnesota governor signed the Jobs and Energy bill into law. Several approved mechanisms may provide additional options and opportunities in future rate cases, including the duration of future MYPs and more certainty regarding recovery of costs and the impact to customers. This bill provides:

- Increased flexibility for utilities to submit a MYP of up to five years;
- The potential for full capital recovery for all proposed years;
- O&M cost recovery based on an index;
- Distribution costs that facilitate grid modernization are eligible for rider recovery;
- Natural gas extension costs for unserved areas can be socialized and are eligible for rider recovery;
- Recovery of plant closure costs, should the MPUC order early plant closure, such as in a resource plan; and
- Allows implementation of interim rates for the first and second years of the MYP.

Annual Automatic Adjustment (AAA) of Charges **—** In June 2013, the DOC proposed that the MPUC adopt a fuel clause incentive that would normalize FCA recovery using monthly patterns derived from averages of the prior three-year period, setting and fixing this level during a rate case with no adjustment between rate cases. NSP-Minnesota and other utilities opposed this proposal. The DOC proposal is pending MPUC action.

Additionally, the DOC has indicated it will review prudence of replacement power costs associated with the Sherco Unit 3 outage event within the 2013 AAA docket. The 2013 and 2012 AAA dockets remain pending.

In September 2015, the 2014 AAA was filed with the MPUC and also remains pending.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation **—** The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants.

The NRC imposed new requirements after events at the nuclear generating plant in Fukushima, Japan in 2011. In 2012, the NRC issued orders which included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Except with respect to the revised order described below, all units are on track to meet the required compliance dates and be fully compliant by December 2016.

In 2013, the NRC issued a revised order with regard to reliable hardened containment vents. Compliance with the revised order will be completed during refueling outages in 2017-2019.

NSP-Minnesota expects that complying with these external event requirements will cost approximately $90 to $100 million at the Monticello and PI plants over the period 2012 through 2018. The majority of these costs have been and are expected to be capital in nature. The costs associated with compliance have been and are expected to continue to be recoverable from customers through regulatory mechanisms and consequently NSP-Minnesota does not expect a material impact on its results of operations, financial position, or cash flows.

The NRC continues to review its requirements for mitigating the risks of external events on nuclear plants. NSP-Minnesota expects the costs associated with compliance will be recoverable from customers.

Nuclear Regulatory Performance — The NRC has a Reactor Oversight Process that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5). Issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern.

At Dec. 31, 2015, Monticello and PI Unit 1 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections.

Based on a December 2015 shutdown, PI Unit 2 will be moved from Column 1 to Column 2 (regulatory response) due to an anticipated white performance indicator related to the level of unplanned rapid shutdowns of the nuclear reactor, of which only a certain level is allowed per year to remain at the green performance level. Plants in Column 2 are subject to special NRC inspections to review and validate that performance issues or inspection findings have been properly addressed. PI Unit 2 returned to service in late February 2016 after addressing the issues leading to shutdown and will be eligible to return to Column 1 once the performance indicator returns to green, subject to an NRC inspection to close the issue. Depending on the unit’s operation in 2016, PI Unit 2 could return to green performance and Column 1 later in 2016.

Monticello Spent Fuel Storage - Dry Shielded Canisters — In the fall of 2013, NSP-Minnesota's Monticello nuclear generating plant conducted a spent fuel loading campaign which resulted in five storage canisters being loaded and placed in the ISFSI and a sixth one being loaded but remaining in the plant pending resolution of weld inspection issues. Successful pressure and leak testing has demonstrated the safety and integrity of all six canisters involved. In December 2013, the NRC initiated an investigation to determine whether two contractor technicians at Monticello deliberately failed to follow procedure in performing Non-Destructive Examinations (NDE) on the six spent fuel storage canisters (Dry Shielded Canisters #11-16) in accordance with procedural requirements and to determine whether the contractors falsified records when recording the NDE results. The investigation determined that the two NDE contractors deliberately violated NRC requirements. NSP-Minnesota has taken several actions to assure that compliance with the NRC's regulations and Monticello's storage license can be demonstrated. In October 2015, NSP-Minnesota and the NRC participated in an alternative dispute resolution (ADR) session on this matter.

In December 2015, the NRC issued a confirmatory order formally approving a settlement reached through the ADR process in which NSP-Minnesota agreed to a timeline for attaining compliance on all six canisters as well as additional training and communications. As a result, the NRC will not issue a notice of violation or impose a civil penalty to NSP-Minnesota for this matter, and will consider the terms of its order as an escalated enforcement action for a period of one year from its issued date. NSP-Minnesota has filed an exemption request with the NRC for the completion of the final canister #16, which is anticipated to be acted upon in 2016. Costs attributable to the six canisters achieving full regulatory compliance within five years, as agreed to in the settlement, are currently being evaluated. No public safety issues have been raised, or are believed to exist, related to handling of spent nuclear fuel at Monticello in regard to this matter.

LLW Disposal — LLW from NSP-Minnesota’s Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello that would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

Nuclear Geologic Repository - Yucca Mountain Project
In 2002, the U.S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository. In 2008, the DOE submitted an application to construct a deep geologic repository at this site to the NRC. In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC approve the withdrawal of the application. In 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application.

The DOE’s decision and the resulting stoppage of the NRC’s review has prompted multiple legal challenges, including the DOE’s authority to stop the project and withdraw the application, the DOE’s authority to continue to collect the nuclear waste fund fee and the NRC’s authority to stop their review of the DOE’s application.

In August 2013, the D.C. Court of Appeals ordered the NRC to complete their review of the DOE’s application to construct the Yucca Mountain repository. In November 2013, the NRC complied by issuing an order to the NRC Staff to complete and publish a safety evaluation report on the proposed Yucca Mountain nuclear spent fuel and waste repository. The NRC Staff completed and published its Safety Evaluation Report in January 2015. The NRC also requested that the DOE prepare a supplemental environmental impact statement (EIS) so the NRC Staff can complete its review. A supplement to the DOE’s EIS was published in August 2015.

In November 2013, the U.S. Court of Appeals ordered the DOE to suspend the collection of the nuclear waste fund fee from nuclear utilities and to recommend to Congress that the nuclear waste fund fee be set to zero. In January 2014, the DOE sent its court mandated proposal to adjust the current fee to zero, which Congress approved in May 2014.

At the time that the DOE decided to stop the Yucca Mountain project and withdraw the application, the U.S. Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. In January 2012, the Blue Ribbon Commission report was issued. In January 2013, the DOE provided its report to Congress relative to their plans to implement the Blue Ribbon Commission’s recommendations including the required legislative changes and authorizations. The report also announced the Obama Administration’s intent to make a pilot consolidated interim storage facility available in 2021, a larger consolidated interim storage facility available in 2025 and a deep geologic repository available in 2048.

Nuclear Spent Fuel Storage
NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. As of Dec. 31, 2015, there were 40 casks loaded and stored at the PI plant and 15 canisters loaded and stored at the Monticello plant. An additional 24 casks for PI and 15 canisters for Monticello have been authorized by the State of Minnesota. This currently authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not begin operation of a consolidated interim storage installation.

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE’s failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contracts between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through 2004. In September 2007, the Court awarded NSP-Minnesota $116.5 million in damages through 2004. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for 2005 through 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013. In January 2014, the United States and NSP-Minnesota agreed to an extension to the settlement agreement which will allow recovery of spent fuel storage costs through 2016. The extension does not address costs for spent fuel storage after 2016; such costs could be the subject of future litigation. In November 2015, NSP-Minnesota received a settlement payment of $13.1 million. NSP-Minnesota has received a total of $227.8 million of settlement proceeds as of Dec. 31, 2015. Amounts received from the installments are being returned to customers through ratemaking proceedings as determined by the MPUC and other state regulators.

NRC Waste Confidence Decision (WCD) — In September 2014, the NRC published a Generic Environmental Impact Statement (GEIS) and revised WCD rule, now called the Continued Storage Rule (CSR) on the temporary on-site storage of spent nuclear fuel. The CSR assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. Issuance of the CSR now allows the NRC to proceed with final license decisions regarding the new and renewed plant and Independent Spent Fuel Storage Installation (ISFSI) operating licenses without the need to litigate contentions related to the continued storage of spent nuclear fuel on-site. This may facilitate potential future spent fuel licensing needs for NSP-Minnesota.

The CSR is currently being challenged before the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) on the grounds that the environmental impact statement is inadequate to satisfy the National Environmental Policy Act. A decision by the D.C. Circuit is anticipated later in 2016.

PI ISFSI License Renewal — The current license to operate an ISFSI at PI expired in October 2013. The NRC granted a renewed license for the ISFSI at PI in December 2015. The new expiration date of the renewed license is Oct. 31, 2053.

See Note 14 to the consolidated financial statements for further discussion regarding nuclear related items.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
NSP System	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**
Coal	15,961	35%	18,079	39%	15,844	36%
Nuclear	12,425	27	13,434	29	12,161	28
Natural Gas	6,689	15	3,402	7	5,550	13
Wind [(a)]	6,235	14	6,243	14	5,481	13
Hydroelectric	3,326	7	3,560	8	3,223	7
Other [(b)]	1,083	2	1,417	3	1,323	3
Total	45,719	100%	46,135	100%	43,582	100%
Owned generation	33,818	74%	33,641	73%	29,249	67%
Purchased generation	11,901	26	12,494	27	14,333	33
Total	45,719	100%	46,135	100%	43,582	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource® RECs. The NSP System uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately eight, seven, and eight million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

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

	Coal [(a)]		Nuclear		Natural Gas		Weighted Average Owned Fuel Cost
NSP System Generating Plants	**Cost**	**Percent**	**Cost**	**Percent**	**Cost**	**Percent**	
2015	$ 2.15	47%	$ 0.83	40%	$ 3.89	13%	$ 1.85
2014	2.23	52	0.89	42	6.27	6	1.94
2013	2.20	49	0.95	40	5.08	11	2.03

(a) Includes refuse-derived fuel and wood.

The cost of natural gas in 2015 decreased due to lower wholesale commodity prices.

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2015 and 2014 were approximately 67 and 27 days usage, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being above optimal levels. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2015 and 2014, coal requirements for the NSP System's major coal-fired generating plants were approximately 8.3 million tons and 9.3 million tons, respectively. Coal requirements for 2015 were lower due to the retirement of Black Dog Units 3 and 4 and relatively low natural gas prices. The estimated coal requirements for 2016 are approximately 7.9 million tons.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 90 percent of their estimated coal requirements in 2016, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 percent of their coal requirements in 2016 and 2017. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

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

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2018 and approximately 59 percent of the requirements for 2019 through 2030;
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 54 percent of the requirements for 2022 through 2030; and
- Current enrichment service contracts cover 100 percent of the requirements through 2026 and approximately 34 percent of the requirements for 2027 through 2030.

Fabrication services for Monticello and PI are 100 percent committed through 2030 and 2019, respectively.

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

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies, transportation and storage services for power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. 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, 2015 and 2014, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately $310 million and $349 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2016 to 2028.

The NSP System also has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, the NSP System was in compliance with mandated RPS, which require generation from renewable resources of 18 percent and 12.9 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively.

- Renewable energy comprised 23.3 percent and 24.2 percent of the NSP System's total energy for 2015 and 2014, respectively;

- Wind energy comprised 13.6 percent and 13.7 percent of the total energy for 2015 and 2014, respectively;
- Hydroelectric energy comprised 7.3 percent and 7.8 percent of the total energy for 2015 and 2014, respectively; and
- Biomass and solar power comprised approximately 2.4 percent and 2.7 percent of the total energy for 2015 and 2014, respectively.

The NSP System also offers customer-focused renewable energy initiatives. Windsource allows customers in Minnesota, Wisconsin, and Michigan to purchase a portion or all of their electricity from renewable sources. In 2015, the number of customers utilizing Windsource increased to approximately 50,000 from 43,000 in 2014.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 1,458 PV systems with approximately 18.3 MW of aggregate capacity and over 915 PV systems with approximately 11.1 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2015 and 2014, respectively.

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners. Currently, the NSP System has more than 120 of these agreements in place, with facilities ranging in size from under one MW to more than 200 MW. The NSP System owns and operates four wind farms which have the capacity to generate 652 MWs.

- Collectively, the NSP System had approximately 2,210 and 1,860 MWs of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, the NSP System also typically receives wind RECs, which are used to meet state renewable resource requirements.

- The average cost per MWh of wind energy under the existing contracts was approximately $42 and $41 for 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and PPAs. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 277.5 MW of capacity. For 2015, PPAs provided approximately 34 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 725 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates. See Item 7 for further discussion.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction **—** Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. NSP-Wisconsin and NSP-Minnesota have been granted continued joint authorization from the FERC to make wholesale electric sales at market-based prices. NSP-Wisconsin is a transmission owning member of the MISO RTO.

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

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities defer the amount of any fuel cost under-collection or over-collection in excess of a two percent annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW after an opportunity for a hearing. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. Fuel cost under-collections that exceed the two percent annual tolerance band for a calendar year may not be recovered if the utility earnings for that year exceed the authorized ROE.

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

Wisconsin Energy Efficiency Program — In Wisconsin, the primary energy efficiency program is funded by the state's utilities, but operated by independent contractors subject to oversight by the PSCW and the utilities. NSP-Wisconsin recovers these costs in rates charged to Wisconsin retail customers.

Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Capacity and Demand.

Energy Sources and Related Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Energy Sources and Related Transmission Initiatives.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse, Wis. to Madison, Wis. Transmission Line — In October 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a Certificate of Public Convenience and Necessity (CPCN) for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. NSP-Wisconsin's half of the line will be shared with three co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

In April 2015, the PSCW issued its order approving a CPCN and route for the project. In June 2015, the PSCW denied two requests for rehearing. Two groups have appealed the CPCN Order to county circuit court. Court action is pending and the CPCN remains in full effect unless one of the parties seeks and receives a stay from the court and posts a bond to cover damages the utilities may incur due to delay. The 180-mile project is expected to cost approximately $580 million. NSP-Wisconsin's portion of the investment is estimated to be approximately $207 million. Construction on the line began in January 2016, with completion anticipated by late 2018.

2015 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the year ended Dec. 31, 2015 were lower than authorized in rates and outside the two percent annual tolerance band established in the Wisconsin fuel cost recovery rules, primarily due to lower load as a result of mild weather, lower natural gas prices and lower purchased power prices in the MISO market. Accordingly, NSP-Wisconsin recorded a deferral of approximately $9.2 million through Dec. 31, 2015. In the first quarter of 2016, NSP-Wisconsin will file a reconciliation of 2015 fuel costs with the PSCW. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2016.

Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Fuel Supply and Costs.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin operates an integrated system with NSP-Minnesota. NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates. See NSP-Minnesota Wholesale and Commodity Marketing Operations.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. PSCo is authorized to make wholesale electric sales at market-based prices to customers outside its balancing authority area.

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

- *ECA* — The ECA recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- *PCCA* — The PCCA recovers purchased capacity payments.
- *SCA* — The SCA recovers the difference between PSCo's actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised on a quarterly basis beginning in January 2015.
- *DSMCA* — The DSMCA recovers DSM, interruptible service option credit costs and performance initiatives for achieving various energy savings goals.
- *RESA* — The RESA recovers the incremental costs of compliance with the RES with a maximum of two percent of the customer's total bill.
- *Wind Energy Service* — Wind Energy Service is a premium service for customers who voluntarily choose to pay an additional charge for renewable resources.
- *TCA* — The TCA recovers costs associated with transmission investment outside of rate cases.
- *CACJA* — The CACJA recovers costs associated with implementing its compliance plan under the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. PSCo's wholesale customers have agreed to pay the full cost of certain renewable energy purchase and generation costs through a fuel clause and in exchange receive RECs associated with those resources. The wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

QSP Requirements — The CPUC established 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. PSCo monitors and records, as necessary, an estimated customer refund obligation under the QSP. The CPUC extended the terms of the current QSP through 2018.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
PSCo	6,678	6,152	6,284	6,493

The peak demand for PSCo's system typically occurs in the summer. The 2015 system peak demand for PSCo occurred on Aug. 5, 2015. The 2014 system peak demand was lower due to reduced wholesale loads and cooler summer weather. The forecast of 2016 system peak assumes normal weather conditions.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — PSCo has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. PSCo also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

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

Colorado ERP and All-Source Solicitation — The CPUC provided final approval to PSCo's plan in December 2013, which includes the following:

- The addition of 450 MW of wind generation PPAs became operational in 2015. These additional PPAs bring the installed wind capacity on PSCo's system in Colorado to 2,560 MW;
- The addition of 170 MW of utility-scale solar generation PPAs, of which 50 MW became operational in 2015 and the remaining 120 MW of utility-scale solar generation is expected to be operational by mid-2016. PSCo has approximately 80 MW of utility-scale solar and approximately 258 MW of customer-sited solar generation;
- The addition of 317 MW of natural gas fired generation PPAs come from existing power plants;
- The accelerated retirements of the coal-fired Arapahoe Unit 3 (45 MW) and Unit 4 (109 MW), which occurred in 2013; and
- The continued operation of Cherokee generating station's Unit 4 as a natural gas facility after 2017.

In addition, PSCo continues to execute on the remaining aspects of CACJA compliance including the recent completion of the new natural gas fired combined cycle unit at Cherokee and the ongoing addition of emissions controls at the Pawnee and Hayden stations. PSCo also retired the Cherokee Unit 3 in August 2015 and expects to retire Valmont Unit 5 coal-fired power plant by the end of 2017.

Brush, Colo. to Castle Pines, Colo. 345 KV Transmission Line — In April 2015, the CPUC granted a CPCN to construct a new 345 KV transmission line originating from Pawnee generating station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. to be placed in service by 2022. The estimated project cost is $178 million. The CPUC's decision requires that project construction begin no earlier than May 2020.

Boulder, Colo. Municipalization — In November 2011, a ballot measure was passed which authorized the formation and operation of a municipal utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage. In May 2014, the City of Boulder (Boulder) City Council passed an ordinance to establish an electric utility.

In 2013, the CPUC ruled that Boulder may not be the retail service provider to any PSCo customers located outside Boulder city limits unless Boulder can establish that PSCo is unwilling or unable to serve those customers. The CPUC also ruled that it has jurisdiction over the transfer of any facilities to Boulder that currently serve any customers located outside Boulder city limits and will determine separation matters. The CPUC has declared that Boulder must receive CPUC transfer approval prior to any eminent domain actions. Boulder appealed this ruling to the Boulder District Court and in January 2015, the Boulder District Court affirmed the CPUC decision. The Boulder District Court also dismissed a condemnation action which Boulder had filed. The CPUC must complete the separation plan proceeding, outlined below, before Boulder may refile a condemnation proceeding.

In July 2015, Boulder filed an application with the CPUC requesting approval of its proposed separation plan. In August 2015, PSCo filed a motion to dismiss Boulder's separation proposal, arguing Boulder's request was not permissible under Colorado law. In December 2015, the CPUC granted the motion to dismiss the application in part, holding that Boulder had no right to condemn PSCo facilities used exclusively to serve customers located outside Boulder city limits. Other portions of Boulder's application were not dismissed, but are stayed until Boulder supplements its application at which time the CPUC will determine whether the application is complete and a proceeding can continue. The CPUC ordered a discovery process to allow Boulder to obtain technical information regarding the electric system and propose a new separation plan. Boulder is expected to refile its plan later this year. PSCo is also challenging Boulder's 2014 formation of its utility in a case that is now before the Colorado Court of Appeals.

Colorado "Our Energy Future" Plan — In January 2016, PSCo introduced the "Our Energy Future" Plan in Colorado. This proposal ties together innovative technology, economic development and customer initiatives to give customers more control over their energy use, prepare for the future energy demands of the state and keep rates competitive. The key components of the plan, which includes several filings with the CPUC, are as follows:

- Two Innovative Clean Technology pilot programs in partnership with leading companies to address electric battery efficiency and reliability including demonstrations to test microgrids and battery technologies for integration of distributed resources;
- Alignment of PSCo's pricing in a more fair and equitable manner for Colorado customers;
- Introduction of Solar*Connect®, a new, cost-based program that will offer customers a choice to sign up for 100 percent solar power and add an incremental 50 MW of solar generation;
- Investing in natural gas reserves to take advantage of historically low natural gas prices by locking in current costs to provide long-term stable rates for customers;
- Exploring opportunities for up to 1,000 MW of additional renewable resources to be presented later this year for consideration by the CPUC; and
- Presenting an intelligent grid proposal later this year focusing on interactive meter technology that will improve customer choice and control of their energy use.

RES Compliance Plan — Colorado law mandates that at least 20 percent of PSCo's energy sales are supplied by renewable energy through 2019, with the percentage increasing to 30 percent by 2020 and includes a distributed generation standard. PSCo is in compliance with the RES as of Dec. 31, 2015.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
PSCo	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	18,601	54%	18,274	53%	19,647	56%
Natural Gas	7,948	23	8,601	25	7,565	22
Wind [(a)]	6,699	19	6,472	19	6,750	19
Hydroelectric	662	2	617	2	655	2
Other [(b)]	705	2	294	1	250	1
Total	34,615	100%	34,258	100%	34,867	100%
Owned generation	22,981	66%	23,023	67%	22,873	66%
Purchased generation	11,634	34	11,235	33	11,994	34
Total	34,615	100%	34,258	100%	34,867	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. PSCo uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Distributed generation from the Solar*Rewards program is not included, and was approximately 245, 197, and 172 million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

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

	Coal		Natural Gas		Weighted Average Owned Fuel Cost
PSCo Generating Plants	Cost	Percent	Cost	Percent	
2015	$ 1.75	75%	$ 3.89	25%	$ 2.29
2014	1.82	75	5.32	25	2.68
2013	1.84	80	4.86	20	2.45

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal **—** PSCo normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2015 and 2014 were approximately 49 and 36 days usage, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being slightly above optimal levels. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2015 and 2014, PSCo's coal requirements for existing plants were approximately 10.5 million tons and 10.3 million tons, respectively. The estimated coal requirements for 2016 are approximately 10.1 million tons.

PSCo has contracted for coal supply to provide 96 percent of its estimated coal requirements in 2016, and a declining percentage of requirements in subsequent years. PSCo's general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 100 percent and 86 percent of its coal requirements in 2016 and 2017, respectively. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Natural gas **—** PSCo uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company, the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 11 to the consolidated financial statements for further discussion.

Most transportation contract pricing is based on FERC approved transportation tariff rates. 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, 2015, PSCo's commitments related to gas supply contracts, which expire in various years from 2016 through 2023, were approximately $750 million and commitments related to gas transportation and storage contracts, which expire in various years from 2016 through 2060, were approximately $684 million.
- At Dec. 31, 2014, PSCo's commitments related to gas supply contracts were approximately $902 million and commitments related to gas transportation and storage contracts were approximately $685 million.

PSCo has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

***PSCo Natural Gas Reserves Investments* —** In January 2016, PSCo filed a request with the CPUC for approval of a long-term natural gas procurement and price hedging framework. Under the proposal, a wholly-owned subsidiary of PSCo, PSCo Gas Reserves Company (PGRCo), will be formed to partner with Wexpro, a subsidiary of Questar Corporation, to acquire, develop and operate natural gas producing properties on a 50/50 joint basis, with production recovered under cost of service pricing through PSCo's GCA. The CPUC has 240 days to review the proposed framework. If approved, PGRCo may invest up to approximately $500 million in gas properties over 10 years, which is not reflected in the current base capital expenditures forecast.

The requested cost of service pricing formulas provide PGRCo and Wexpro different risks and incentives. For PGRCo, the investment would include all costs of property acquisition and development. The ROE would be based on PSCo's allowed ROE, adjusted up or down a maximum of 100 basis points, based on the price of gas produced relative to market prices.

Following approval of the framework, PSCo plans to partner with Wexpro to seek to identify and acquire specific natural gas producing properties that would be beneficial to PSCo's gas customers, and seek CPUC approval of these specific investments.

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, PSCo was in compliance with mandated RPS, which require generation from renewable resources of 20 percent of electric retail sales.

- Renewable energy comprised 21.9 percent and 21.4 percent of PSCo's total energy for 2015 and 2014, respectively;
- Wind energy comprised 19.4 percent and 18.9 percent of the total energy for 2015 and 2014, respectively; and
- Hydroelectric, biomass and solar power comprised approximately 2.6 percent and 2.5 percent of the total energy for 2015 and 2014.

PSCo also offers customer-focused renewable energy initiatives. Windsource allows customers to purchase a portion or all of their electricity from renewable sources. In 2015, the number of customers utilizing Windsource increased to approximately 45,000 from 41,000 in 2014.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 29,500 PV systems with approximately 258 MW of aggregate capacity and over 24,000 PV systems with approximately 221 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2015 and 2014, respectively. Additionally, 24 community solar gardens with 16.6 MW of capacity and 14 gardens with 9.6 MW of capacity have been completed in Colorado as of Dec. 31, 2015 and 2014, respectively.

Wind — PSCo acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Colorado. Currently, PSCo has 19 of these agreements in place, with facilities ranging in size from two MW to over 300 MW.

- PSCo had approximately 2,560 MW and 2,340 MW of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, PSCo also typically receives wind RECs which are used to meet state renewable resource requirements.

- The average cost per MWh of wind energy under these contracts was approximately $42 and $45 in 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in wind technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. See Item 7 for further discussion.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. Each municipality can deny SPS' rate increases. SPS can then appeal municipal rate decisions to the PUCT, which hears all municipal rate denials in one hearing. The NMPRC also has jurisdiction over the issuance of securities. SPS is regulated by the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. As approved by the FERC, SPS operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

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

- *DCRF* — The DCRF rider recovers certain distribution costs in Texas that are not included in base rates.
- *EECRF* — The EECRF rider recovers costs associated with providing energy efficiency programs in Texas.
- *EE rider* — The EE rider recovers costs associated with providing energy efficiency programs in New Mexico.
- *FPPCAC* — The FPPCAC adjusts monthly to recover the difference between the actual fuel and purchased power costs and the amount included in base rates of SPS' New Mexico retail jurisdiction.
- *PCRF* — The PCRF rider allows recovery of certain purchased power costs in Texas that are not included in base rates.
- *RPS* — The RPS rider recovers deferred costs associated with renewable energy programs in New Mexico.
- *TCRF* — The TCRF rider recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges in Texas that are not included in base rates.

Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric tariff. SO_2 and NOx allowance revenues and costs are also recovered through the fixed fuel and purchased energy recovery factor. The regulations allow retail fuel factors to change up to three times per year.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of fuel and purchased energy expenses. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed four percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

PUCT regulations require periodic examination of SPS' fuel and purchased energy costs, the efficient use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years. SPS will be required to file its next fuel reconciliation application by December 2016.

Each New Mexico utility operating with a FPPCAC as part of its tariff must file an application for continued use at intervals of no more than four years from the date the FPPCAC is approved or continued by the NMPRC. In October 2015, the NMPRC granted SPS authority to continue using its FPPCAC to collect its fuel and purchase power costs. SPS will be required to file a request for continuation of its FPPCAC by October 2019.

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

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
SPS	5,056	4,871	4,678	4,886

The peak demand for the SPS system typically occurs in the summer. The 2015 system peak demand for SPS occurred on July 28, 2015. The 2015 peak demand was lower due to wetter and cooler summer weather and a reduction in a partial requirements wholesale contractual agreement. The 2016 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — SPS has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. SPS also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations or to obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers, including PSCo, to deliver power and energy to its native load customers.

High Priority Incremental Load Study Report — In April 2014, the SPP Board of Directors approved the High Priority Incremental Load Study Report, a reliability assessment that evaluated the anticipated transmission needs of certain parts of the SPP resulting from expected load growth in the area. As a result of this study, SPS has received NTCs and conditional NTCs for 44 new transmission projects to be placed into service by 2020, some of which are already in service. SPS is developing plans for the remaining projects and submitting CCNs to the PUCT and the NMPRC. The estimated cost for these projects is $203 million. These projects are intended to provide regional reliability benefits as well as the ability to serve the increase in load in southeastern New Mexico.

Potash Junction Substation to Roadrunner Substation 345 KV Transmission Line — In December 2014, the NMPRC issued a CCN for a new 345 KV transmission line from the Potash Junction substation to the Roadrunner substation, both near Carlsbad, N.M. The transmission line is 40 miles long and cost $59.6 million. The line was placed into service in October 2015.

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In June 2015, SPS filed a CCN with the PUCT for the Yoakum County to Texas/New Mexico State line portion of this 345 KV line project and the PUCT is expected to approve this CCN in the first quarter of 2016. This line will connect the TUCO substation near Lubbock, Texas with the Yoakum County substation, continuing on to the Hobbs Plant substation near Hobbs, New Mexico. CCNs for the TUCO to Yoakum County line segment and for the Texas/New Mexico state line to Hobbs Plant segment are planned to be filed in mid-2016. The estimated project cost is $242 million. This line is scheduled to be in service in 2020.

Hobbs Plant Substation to China Draw Substation 345 KV Transmission Line — The Hobbs Plant to China Draw transmission line will connect the Hobbs Plant substation to the China Draw substation near Malaga, N.M. with terminations at a proposed Kiowa substation near Carlsbad, N.M. and at the North Loving substation, near Loving, N.M. SPS plans to file a CCN for this line in New Mexico during spring 2016. The estimated project cost is $139 million. The line is anticipated to be in service in 2018.

SPS Resource Plans — SPS was required to develop and implement a renewable portfolio plan by 2015, in which 15 percent of its energy to serve its New Mexico retail customers is produced by renewable resources. The requirement was met through PPAs, including wind, solar and distributive generation. In 2020, the renewable resource production requirement increases to 20 percent. In addition, SPS indicated that it was evaluating water supply issues at its Tolk facility and if additional investment is required to operate the plant through its existing life.

Texas Legislation — In June 2015, the Texas Governor signed HB 1535 into law. As a result, SPS may reduce regulatory lag through earlier inclusion of certain capital additions in rate base, as well as expediting the implementation of new rates. Key provisions of the bill are as follows:

- Utilities may include actual and estimated post-test year capital additions up through 30-days before the filing date;
- A new natural gas generating unit may be included in rate base as long as it is in service before the proposed effective rate date;
- Rates will go into effect 155 days after filing (previously it was 185 days). If the case is not final by this date, then a utility can go back and surcharge; and
- Establishes time limits for the PUCT to rule on a new generation plant request for a certificate of convenience and necessity.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
SPS	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	12,441	44%	12,770	48%	14,184	49%
Natural Gas	10,514	36	10,068	37	11,235	38
Wind [(a)]	5,252	19	3,762	14	3,507	12
Other [(b)]	150	1	180	1	167	1
Total	28,357	100%	26,780	100%	29,093	100%
Owned generation	16,480	58%	16,956	63%	18,814	65%
Purchased generation	11,877	42	9,824	37	10,279	35
Total	28,357	100%	26,780	100%	29,093	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. SPS uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Distributed generation from the Solar*Rewards program is not included, was approximately 13, 10, and 11 million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

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

	Coal		Natural Gas		Weighted Average Owned Fuel Cost
SPS Generating Plants	Cost	Percent	Cost	Percent	
2015	$ 2.12	73%	$ 3.11	27%	$ 2.39
2014	2.07	71	4.76	29	2.85
2013	2.14	71	3.97	29	2.68

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers. The coal supply contract with TUCO expires in December 2016 and 2017 for Harrington and Tolk, respectively. SPS normally maintains approximately 43 days of coal inventory. As of Dec. 31, 2015 and 2014, coal inventories at SPS were approximately 76 and 17 days supply, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being above optimal levels. TUCO has coal agreements to supply 87 percent of SPS' estimated coal requirements in 2016, and a declining percentage of the requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three.

Natural gas — SPS uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel; which typically is purchased with terms of one year or less. The transportation and storage contracts expire in various years from 2016 to 2033. All of the natural gas supply contracts have variable pricing that is tied to various natural gas indices.

Most transportation contract pricing is based on FERC and Railroad Commission of Texas approved transportation tariff rates. 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. SPS' commitments related to gas supply contracts were approximately $10 million and $3 million and commitments related to gas transportation and storage contracts were approximately $192 million and $222 million at Dec. 31, 2015 and 2014, respectively.

SPS has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

SPS' renewable energy portfolio includes wind and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, SPS is in compliance with mandated RPS, which require generation from renewable resources of approximately four percent and 15 percent of Texas and New Mexico electric retail sales, respectively.

- Renewable energy comprised 19.0 percent and 14.7 percent of SPS' total energy for 2015 and 2014, respectively;
- Wind energy comprised 18.5 percent and 14.0 percent of the total energy for 2015 and 2014, respectively; and
- Solar power comprised approximately 0.5 percent and 0.4 percent of the total energy for 2015 and 2014, respectively.

SPS also offers customer-focused renewable energy initiatives. Windsource allows customers in New Mexico to purchase a portion or all of their electricity from renewable sources. The number of customers utilizing Windsource decreased to approximately 880 in 2015 from 900 in 2014.

Additionally, to encourage the growth of solar energy on the system in New Mexico, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 144 PV systems with approximately 8.0 MW of aggregate capacity and over 129 PV systems with approximately 7.7 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2015 and 2014, respectively.

Wind — SPS acquires its wind energy from independent power producers (IPP) contracts and qualified facilities (QF) tariffs with wind farm owners, primarily located in the Texas Panhandle area of Texas and New Mexico. SPS currently has 37 of these agreements in place, with facilities ranging in size from under two MW to 250 MW for a total capacity greater than 1,800 MW.

- SPS had approximately 1,775 MW and 1,500 MW of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, SPS also typically receives wind RECs, which are used to meet state renewable resource requirements.

- The average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately $24 and $26 for 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries and transmission-only subsidiaries, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 12 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

***FERC Order, New ROE Policy* —** In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In March, 2015, FERC upheld the new ROE methodology and denied rehearing. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. As part of a global settlement approved by the FERC in October 2015, three ROE complaints against SPS were resolved. FERC is not expected to issue orders in any litigated ROE complaint proceedings until at least mid-2016. See Note 12 to the consolidated financial statements for discussion of the MISO ROE Complaints.

SPS Asset Transfer to XEST — In October 2015, SPS submitted filings to the PUCT, NMPRC and Kansas Corporation Commission (KCC) seeking approval to transfer ownership of SPS' 345kV transmission assets in Kansas and Oklahoma to XEST at net book value, estimated at approximately $103 million as of Dec. 31, 2015. After the proposed asset transfer, the transmission facilities would remain subject to SPP functional control, with revenue requirements recovered through the SPP Tariff. SPS and XEST also proposed to enter into a transmission operation and maintenance agreement (O&M Agreement) under which SPS would operate and maintain the transferred facilities and be reimbursed for providing those services to XEST at cost.

The KCC is expected to issue a decision within 10 months of the October filing. The hearings in the NMPRC and PUCT proceedings are scheduled for August 2016 and October 2016, respectively, with each decision expected several months later. Requests for FERC approval of the asset transfer and O&M Agreement were submitted in January 2016, and requested FERC action by June 30, 2016. Based on the procedural schedules for the required regulatory approvals, SPS expects the proposed asset transfer to take place no earlier than late 2016 or early 2017.

***NERC Critical Infrastructure Protection Requirements* —** The FERC has approved Version 5 of NERC's critical infrastructure protection standards, which added additional requirements to strengthen grid security controls. Requirements must be applied by Xcel Energy to high and medium impact assets by April 1, 2016 and to low impact assets by April 1, 2017. Xcel Energy is currently in the process of implementing initiatives to meet the compliance deadlines. The additional cost for compliance is anticipated to be recoverable through rates.

NERC Physical Security Requirements — In November 2014, the FERC approved NERC's proposed critical infrastructure protection standard related to physical security for bulk electric system facilities. The new standard became enforceable in October 2015 with staggered milestone deliverable dates through 2016. Xcel Energy has performed an initial risk assessment and is in the process of developing physical security plans in accordance with the requirements of the standard. The additional cost for compliance is anticipated to be recoverable through rates.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO have been engaged in a longstanding dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagree over MISO's authority to transmit power between the traditional MISO region in the Midwest and the Entergy system. Several cases were filed with the FERC by MISO and SPP between 2011 and 2014. In June 2014, the FERC set the issues for settlement judge and hearing procedures.

In January 2016, FERC approved a settlement between SPP, MISO and other parties that resolves various disputed matters and provide a defined settlement compensation plan by MISO to SPP. MISO will pay SPP $16 million for the two-year retroactive period and $16 million annually prospectively, subject to a true-up. Separate settlement discussions regarding the MISO tariff change to recover SPP charges are ongoing. NSP-Minnesota and NSP-Wisconsin expect to be able to recover any resulting MISO charges in retail rates. In January 2016, SPP filed a proposal regarding distribution of the revenues to SPP members, including SPS. FERC approval is pending. The revenue allocated to SPS is not expected to be material.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2015	2014	2013
Electric sales (Millions of KWh)			
Residential	24,498	24,857	25,306
Large C&I	27,719	27,657	27,206
Small C&I	35,806	36,022	35,873
Public authorities and other	1,071	1,104	1,098
Total retail	89,094	89,640	89,483
Sales for resale	15,283	14,931	15,065
Total energy sold	104,377	104,571	104,548
Number of customers at end of period			
Residential	3,023,494	2,994,075	2,965,717
Large C&I	1,229	1,128	1,132
Small C&I	429,617	426,289	422,553
Public authorities and other	68,595	68,306	67,998
Total retail	3,522,935	3,489,798	3,457,400
Wholesale	47	44	65
Total customers	3,522,982	3,489,842	3,457,465
Electric revenues (Thousands of Dollars)			
Residential	$ 2,891,371	$ 2,956,576	$ 2,906,208
Large C&I	1,689,695	1,789,742	1,694,720
Small C&I	3,303,838	3,382,750	3,248,586
Public authorities and other	136,730	143,442	138,126
Total retail	8,021,634	8,272,510	7,987,640
Wholesale	660,590	795,425	691,204
Other electric revenues	593,762	397,955	355,201
Total electric revenues	$ 9,275,986	$ 9,465,890	$ 9,034,045
KWh sales per retail customer	25,290	25,686	25,882
Revenue per retail customer	$ 2,277	$ 2,370	$ 2,310
Residential revenue per KWh	11.80¢	11.89¢	11.48¢
Large C&I revenue per KWh	6.10	6.47	6.23
Small C&I revenue per KWh	9.23	9.39	9.06
Total retail revenue per KWh	9.00	9.23	8.93
Wholesale revenue per KWh	4.32	5.33	4.59

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
Xcel Energy	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**
Coal	47,003	43%	49,123	46%	49,675	46%
Natural Gas	25,151	23	22,071	21	24,350	23
Wind [(a)]	18,186	17	16,478	15	15,738	14
Nuclear	12,895	12	13,503	12	12,177	11
Hydroelectric	4,001	4	4,203	4	3,900	4
Other [(b)]	1,456	1	1,795	2	1,704	2
Total	108,692	100%	107,173	100%	107,544	100%
Owned generation	73,279	67%	73,620	69%	70,936	66%
Purchased generation	35,413	33	33,553	31	36,608	34
Total	108,692	100%	107,173	100%	107,544	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. Xcel Energy uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately 266, 222, and 198 million net KWh for 2015, 2014 and 2013, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of the utility subsidiaries are uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small C&I customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2015, average annual sales to the typical residential customer declined 17 percent, while sales to the typical small C&I customer declined 9 percent, each on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law in January 2012 (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure if records are inadequate. This process could cause temporary or permanent limitations on throughput for affected pipelines.

In addition, the Pipeline Safety Act requires PHMSA to issue reports and develop new regulations including: requiring use of automatic or remote-controlled shut-off valves; requiring testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to $2 million per day for related violations. While Xcel Energy cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, it is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo and NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA and GUIC riders, respectively.

NSP-Minnesota

Public Utility Regulation

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

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation service and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. 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.

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

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 774,044 MMBtu, which occurred on Jan. 12, 2015 and 752,931 MMBtu, which occurred on Jan. 2, 2014.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 620,180 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 30 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 219,200 MMBtu of natural gas per day, or approximately 27 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. In October 2015, the MPUC approved NSP-Minnesota's contract demand levels for the 2014 through 2015 heating season. Demand levels filed with the MPUC in 2015 for the 2015 through 2016 heating season were approved in February 2016.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

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

2015	$	4.07
2014		6.17
2013		4.53

The cost of natural gas in 2015 decreased due to lower wholesale commodity prices.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2016 through 2033.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, NSP-Minnesota was committed to approximately $207 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 32 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

NSP-Wisconsin

Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction* —** NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, the PSCW and the MPSC for pipeline safety compliance.

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

NSP-Wisconsin's natural gas rate schedules for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections.

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 158,719 MMBtu, which occurred on Jan. 7, 2015, and 163,520 MMBtu, which occurred on Jan. 6, 2014.

NSP-Wisconsin purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 139,127 MMBtu per day. In addition, NSP-Wisconsin contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 31 percent of winter natural gas requirements and 34 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 12 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 2015-2016 supply plan was approved by the PSCW in September 2015.

Natural Gas Supply and Costs

NSP-Wisconsin actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Wisconsin conducts natural gas price hedging activity that has been approved by the PSCW.

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

2015	$	4.11
2014		6.52
2013		4.51

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 2016 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, NSP-Wisconsin was committed to approximately $55 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 11 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

PSCo

Public Utility Regulation

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

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

- *GCA* — The GCA recovers the actual costs of purchased natural gas and transportation to meet the requirements of its customers and is revised quarterly to allow for changes in natural gas rates.
- *DSMCA* — The DSMCA recovers costs of DSM and performance initiatives to achieve various energy savings goals.
- *PSIA* — The PSIA recovers costs associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines. The rider was extended through 2018.

QSP Requirements — The CPUC established 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. The CPUC has extended the terms of the QSP through 2018.

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 PSCo was 1,633,493 MMBtu, which occurred on March 4, 2015 and 2,116,747 MMBtu, which occurred on Dec. 30, 2014.

PSCo purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,818,277 MMBtu per day, which includes 854,852 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo's city gate meter stations.

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

Natural Gas Supply and Costs

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

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

2015	$	3.92
2014		4.91
2013		4.20

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, PSCo was committed to approximately $1.1 billion in such obligations under these contracts, which expire in various years from 2016 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2015, PSCo purchased natural gas from approximately 32 suppliers.

See Items 1A and 7 for further discussion of natural gas supply and costs.

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for certain of its generation facilities and operates natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce; and to the jurisdiction of the DOT and the PUCT for pipeline safety compliance.

See Items 1A and 7 for further discussion of natural gas supply and costs.

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2015	2014	2013
Natural gas deliveries (Thousands of MMBtu)			
Residential	135,394	152,269	150,280
C&I	86,093	95,879	92,849
Total retail	221,487	248,148	243,129
Transportation and other	125,263	124,000	125,057
Total deliveries	346,750	372,148	368,186
Number of customers at end of period			
Residential	1,814,321	1,795,190	1,776,849
C&I	156,306	155,515	154,646
Total retail	1,970,627	1,950,705	1,931,495
Transportation and other	6,981	6,594	6,320
Total customers	1,977,608	1,957,299	1,937,815
Natural gas revenues (Thousands of Dollars)			
Residential	$ 1,042,884	$ 1,320,207	$ 1,126,859
C&I	547,165	727,071	586,548
Total retail	1,590,049	2,047,278	1,713,407
Transportation and other	82,032	95,460	91,272
Total natural gas revenues	$ 1,672,081	$ 2,142,738	$ 1,804,679
MMBtu sales per retail customer	112.39	127.21	125.88
Revenue per retail customer	$ 807	$ 1,050	$ 887
Residential revenue per MMBtu	7.70	8.67	7.50
C&I revenue per MMBtu	6.36	7.58	6.32
Transportation and other revenue per MMBtu	0.65	0.77	0.73

GENERAL

Seasonality

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. See Item 7 for further discussion.

Competition

Xcel Energy is a vertically integrated utility in all of its jurisdictions, subject to traditional cost-of-service regulation by state public utilities commissions. However, Xcel Energy is subject to different public policies that promote competition and the development of energy markets. Xcel Energy's industrial and large commercial customers have the 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, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with solar generation (depending on jurisdiction, rooftop solar or solar gardens) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states have policies designed to promote the development of solar and other distributed energy resources through significant incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. See Item 7 and Notes 12 and 13 to the consolidated financial statements for further discussion.

There are significant present and future environmental regulations to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. Xcel Energy has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If these future environmental regulations do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. We believe, based on prior state commission practice, we would recover the cost of these initiatives through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Xcel Energy adopted a methodology for calculating CO_2 emissions based on the reporting protocols of The Climate Registry, a nonprofit organization that provides and compiles GHG emissions data from reporting entities. Starting in 2011, Xcel Energy began reporting GHG emissions to the EPA under the EPA's mandatory GHG Reporting Program.

Based on The Climate Registry's current reporting protocol, Xcel Energy estimated that its current electric generating portfolio emitted approximately 56.6 million and 57.6 million tons of CO_2 in 2015 and 2014, respectively. Xcel Energy also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates these non-owned facilities emitted approximately 10.2 million and 11.4 million tons of CO_2 in 2015 and 2014, respectively. Estimated total CO_2 emissions associated with service to Xcel Energy electric customers decreased by 2.2 million tons in 2015 compared to 2014. The decrease in emissions was associated with a decrease of 5.0 million net MWh of generation since 2011. The average annual decrease in CO_2 emissions since 2011 is approximately 2.9 million tons of CO_2 per year.

CAPITAL SPENDING AND FINANCING

See Item 7 for a discussion of expected capital expenditures and funding sources.

EMPLOYEES

As of Dec. 31, 2015, Xcel Energy had 11,601 full-time employees and 86 part-time employees, of which 5,514 were covered under collective-bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

EXECUTIVE OFFICERS

Ben Fowke, 57, Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc., August 2011 to present. Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS January 2015 to present. Previously, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to August 2011.

Christopher B. Clark, 49, President and Director, NSP-Minnesota, January 2015 to present. Previously, Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota, October 2012 to December 2014; Managing Director, Government and Regulatory Affairs, NSP-Minnesota, January 2012 to October 2012; Managing Attorney, Xcel Energy Inc., November 2007 to January 2012.

David L. Eves, 57, President and Director, PSCo, January 2015 to present. Previously, President, Director and Chief Executive Officer, PSCo, December 2009 to December 2014.

David T. Hudson, 55, President and Director, SPS, January 2015 to present. Previously, President, Director and Chief Executive Officer, SPS, January 2014 to December 2014; Director, Community Service & Economic Development, SPS, April 2011 to January 2014; Director, Strategic Planning, SPS, May 2008 to April 2011.

Kent T. Larson, 56, Executive Vice President and Group President Operations, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Group President Operations, Xcel Energy Services Inc., August 2014 to December 2014; Senior Vice President Operations, Xcel Energy Services Inc., September 2011 to August 2014; Chief Energy Supply Officer, Xcel Energy Services Inc., March 2010 to September 2011.

Teresa S. Madden, 60, Executive Vice President, Chief Financial Officer, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Chief Financial Officer, Xcel Energy Inc., September 2011 to December 2014; Vice President and Controller, Xcel Energy Inc., January 2004 to September 2011. Xcel Energy has previously announced that Teresa Madden will retire in 2016.

Marvin E. McDaniel, Jr., 56, Executive Vice President, Group President, Utilities, and Chief Administrative Officer, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Chief Administrative Officer, Xcel Energy Inc., August 2012 to December 2014; Senior Vice President and Chief Administrative Officer, Xcel Energy Services Inc., September 2011 to August 2012; Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August 2009 to September 2011 and Vice President, Talent and Technology Business Areas, Xcel Energy Services Inc., August 2009 to September 2011.

Timothy O’Connor, 56, Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc., February 2013 to present. Previously, Acting Chief Nuclear Officer, NSP-Minnesota, September 2012 to February 2013; Vice President, Engineering and Nuclear Regulatory Compliance and Licensing July 2012 to September 2012; Monticello Site Vice President, May 2007 to July 2012.

Judy M. Poferl, 56, Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Corporate Secretary, Xcel Energy Inc., May 2013 to December 2014; President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to May 2013.

Jeffrey S. Savage, 44, Senior Vice President, Controller, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Controller, Xcel Energy Inc., September 2011 to December 2014; Senior Director, Financial Reporting, Corporate and Technical Accounting, Xcel Energy Services Inc., December 2009 to September 2011.

Mark E. Stoering, 55, President and Director, NSP-Wisconsin, January 2015 to present. Previously, President, Director and Chief Executive Officer, NSP-Wisconsin, January 2012 to December 2014; Vice President, Portfolio Strategy and Business Development, Xcel Energy Services Inc., August 2000 to December 2011.

Scott M. Wilensky, 59, Executive Vice President, General Counsel, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, General Counsel, Xcel Energy Inc., September 2011 to December 2014; Vice President, Regulatory and Resource Planning, Xcel Energy Services Inc., September 2009 to September 2011.

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

Item 1A — Risk Factors

Like other companies in our industry, Xcel Energy is subject to a variety of risks, many of which are beyond our control. Important risks that may adversely affect the business, financial condition and results of operations are further described below. These risks should be carefully considered together with the other information set forth in this report and in future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board is the oversight of material risk, and our Board employs an effective process for doing so. As outlined below, management and each Board committee has responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economies and the environment when identifying, assessing, managing and mitigating risk. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

At a threshold level, Xcel Energy has developed a robust compliance program and promotes a culture of compliance, including tone at the top, which mitigates risk. The process for risk mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups and overall business management to mitigate the risks inherent in the implementation strategy. Building on this culture of compliance, Xcel Energy manages and further mitigates risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of internal corporate areas such as internal audit, the corporate controller and legal services.

Management communicates regularly with the Board and key stakeholders regarding risk. Senior management presents a periodic assessment of key risks to the Board. The presentation and the discussion of the key risks provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Management also provides information to the Board in presentations and communications over the course of the year.

The Board approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of the Company. First, the Board as a whole regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board assigns oversight of certain critical risks to each of its four standing committees to ensure these risks are well understood and given focused oversight by the committee with the most applicable expertise. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. New risks are considered and assigned as appropriate during the annual Board and committee evaluation process, and committee charters and annual work plans are updated accordingly. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board for consideration where deemed appropriate to ensure broad Board understanding of the nature of the risk. Finally, the Board conducts an annual strategy session where the Company's future plans and initiatives are reviewed and confirmed.

Risks Associated with Our Business

Environmental Risks

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

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental requirements including those for protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archaeological and historical resources), licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, shift generation to lower-emitting but potentially more costly facilities, install pollution control equipment at our facilities, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities, either due to the difficulty in assuring compliance or that the costs of compliance makes operation of the units no longer economical. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2015, these sites included:

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

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

In addition, existing environmental laws or regulations may be revised, and new laws or regulations may be adopted or become applicable to us, including but not limited to, regulation of mercury, NOx, SO_2, CO_2 and other GHGs, particulates, cooling water intakes, water discharges and ash management. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

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

Climate change can create physical and financial risk. Physical risks from climate change can include changes in weather conditions, changes in precipitation and extreme weather events.

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages, whether caused by climate change or otherwise, could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economic health, which could impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of CO_2 emissions under section 111(d) of the CAA, or additional environmental regulation could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Financial Risks

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

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

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment. Our utility subsidiaries provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital, in a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that the applicable regulatory commission will judge all the costs of our utility subsidiaries to have been prudent, which could result in cost disallowances, or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements and there is no assurance that regulators would allow full recovery of all remaining costs. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, adverse regulatory rulings 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 debt payments and the payment of dividends on our common stock.

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

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time, or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any downgrade could lead to higher borrowing costs. Also, our utility subsidiaries may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy. Capital market disruption events and resulting broad financial market distress could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning fund and master pension trust, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates.

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

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires broad clearing of financial swap transactions through a central counterparty, which could lead to additional margin requirements that would impact our liquidity. However, we have taken advantage of an exception to mandatory clearing afforded to commercial end-users who are not classified as a major swap participant. The Board of Directors has authorized Xcel Energy and its subsidiaries to take advantage of this end-user exception.

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

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

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

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions, including mortality tables, have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans with modifications that allowed additional flexibility in the timing of contributions. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company could trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Changes in industry standards utilized by management in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

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

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness and pay dividends depends upon the operating cash flows of our subsidiaries and the payment dividends to us. 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 dividends on our common stock. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets. Also, our utility subsidiaries are regulated by various state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

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

Operational Risks

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

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

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

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

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

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance 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. For example, similar to pensions, interest rate and other assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

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

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

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota's production and transmission system, and NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

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

Most electric utility investments are long-lived and are planned to be used for decades. Transmission and generation investments typically have long lead times, and therefore are planned well in advance of when they are brought in-service subject to long-term resource plans. These plans are based on numerous assumptions over the planning horizon such as: sales growth, customer usage, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. The electric utility sector is undergoing a period of significant change. For example, public policy has driven increases in appliance and lighting efficiency and energy efficient buildings, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease carbon dioxide emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. These changes introduce additional uncertainty into long term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide, and that the preference for the types of additions may change from planning to execution.

The resource plans reviewed and approved by our state regulators assume continuation of the traditional utility cost of service model under which utility costs are recovered from customers as they receive the benefit of service. Xcel Energy is engaged in significant and ongoing infrastructure investment programs to accommodate distributed generation and maintain high system reliability. Xcel Energy is also investing in renewable and natural gas-fired generation to reduce our carbon dioxide emissions profile. Early plant retirements could expose us to premature financial obligations, which could result in less than full recovery of all remaining costs. Both decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation puts downward pressure on load growth. This could lead to under recovery of costs, excess resources to meet customer demand, and increases in electric rates.

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

Our natural gas transmission and distribution activities include a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. 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 effect on our financial position and results of operations. For our natural gas transmission or distribution lines located near populated areas, the level of potential damages resulting from these risks is greater.

Additionally, the operating or other costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant. The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

Public Policy Risks

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

The EPA is regulating GHGs from power plants with state plans to achieve the EPA's goals due by September 2018. Increased public awareness and concern regarding climate change may result in more state, regional and/or federal requirements to reduce or mitigate the effects of GHGs. Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system. International agreements could have an impact to the extent they lead to future federal or state regulations.

The United States continues to participate in international negotiations related to the United Nations Framework Convention on Climate Change (UNFCCC). In December 2015, the 21st Conference of the Parties to the UNFCCC reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions"), with a goal of holding the increase in global average temperature to below 2$_{o}$ Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5$_{o}$ Celsius. The Paris Agreement could result in future additional GHG reductions in the United States.

We have been, and in the future may be, subject to climate change lawsuits. An adverse outcome in any of these cases could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows and financial condition if such costs are not recovered through regulated rates.

The form and stringency of GHG regulation in the power sector has become more clear with the finalization of the CPP by the EPA. The legality of the CPP is being challenged in the courts. In addition, uncertainties remain regarding implementation plans in our states (and the federal plan imposed by the EPA for states who do not submit approvable plans), including what opportunities are available to reduce costs, whether and what type of emission trading will be available, how states will allocate the reduction burden among utilities, what actions are creditable and the indirect impact of carbon regulation on natural gas and coal prices.

An important factor is our ability to recover the costs incurred to comply with any regulatory requirements in a timely manner. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include rules associated with emissions of SO_2 and NOx, mercury, regional haze, ozone and particulate matter, water intakes, water discharges and ash management. The costs of investment to comply with these rules could be substantial and in some cases would lead to early retirement of coal units. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of up to $1 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. If a serious reliability incident did occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance.

We attempt to mitigate the risk of regulatory penalties through formal training on such prohibited practices and a compliance function that reviews our interaction with the markets under FERC and CFTC jurisdictions. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in our customer base is correlated with economic conditions. While the number of customers is growing, sales growth is relatively modest due to an increased focus on energy efficiency including federal standards for appliance and lighting efficiency and distributed generation, primarily solar PV. Instability in the financial markets also may affect the cost of capital and our ability to raise capital, which is discussed in the capital market risk section above.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt.

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

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

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities. Any such disruption could result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material 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 effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. In addition, 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. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection. In addition, we may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

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

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

The degree to which we are able to maintain day-to-day operations in response to unforeseen events will in part determine the financial impact of certain events on our financial condition and results. It is difficult to predict the magnitude of such events and associated impacts.

A cyber incident or cyber security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (e.g., information about our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or exposing us to liability. Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. In addition, such an event would likely receive regulatory scrutiny at both the federal and state level. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and corresponding regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures designed to protect our information technology systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. We are unable to quantify the potential impact of cyber security incidents on our business.

Rising energy prices could negatively impact our business.

Although commodity prices are currently relatively low, if fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. Low fuel costs could have a positive impact on sales, although particularly on the southern part of our service territory, low oil prices could negatively impact oil and gas production activities. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

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

Our electric and natural gas utility businesses are seasonal, 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 depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS is subject to the lien of their first mortgage bond indentures.

Electric Utility Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)	
Steam:				
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511	
Sherco-Becker, Minn.				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	607	
PI-Welch, Minn.				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse-derived fuel	Various	36	(b)
Combustion Turbine:				
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327	
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	282	
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453	
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	538	
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470	
Various locations, 14 Units	Natural Gas	Various	67	
Wind:				
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101	(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201	(c)
Pleasant Valley-Mower County, Minn., 100 Units	Wind	2015	200	(c)
Border-Rolette County, N.D., 75 Units	Wind	2015	150	(c)
		Total	7,144	

(a) Based on NSP-Minnesota's ownership of 59 percent.
(b) Refuse-derived fuel is made from municipal solid waste.
(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)	
Steam:				
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	56	
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	16	(a)
Combustion Turbine:				
Flambeau Station-Park Falls, Wis., 1 Unit	Natural Gas	1969	12	
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	122	
Wheaton-Eau Claire, Wis., 4 Units	Natural Gas	1973	183	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	524	

(a) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)	
Steam:				
Cherokee-Denver, Colo., 1 Unit	Coal	1968	352	
Comanche-Pueblo, Colo.				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(a)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83	(b)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	237	(c)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505	
Valmont-Boulder, Colo., 1 Unit	Coal	1964	184	
Combustion Turbine:				
Cherokee-Denver, Colo., 3 Units	Natural Gas	2015	576	
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264	
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969	
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	173	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
		Total	5,319	

(a) Based on PSCo's ownership interest of 67 percent of Unit 3.
(b) Based on PSCo's ownership interest of 10 percent.
(c) Based on PSCo's ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

SPS

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	411
Combustion Turbine:			
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	10
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	212
Jones-Lubbock, Texas, 2 Units	Natural Gas	2011-2013	338
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61
		Total	4,426

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2015:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	8,425	1,152	2,630	8,108
230 KV	2,157	—	12,553	9,302
161 KV	395	1,577	—	—
138 KV	—	—	92	—
115 KV	7,502	1,810	4,925	12,427
Less than 115 KV	84,074	32,355	75,155	23,299

Electric utility transmission and distribution substations at Dec. 31, 2015:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	349	204	229	444

Natural gas utility mains at Dec. 31, 2015:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	136	—	2,278	11
Distribution	10,084	2,342	22,045	—

Item 3 — Legal Proceedings

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 13 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 12 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

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

Quarterly Stock Data

Xcel Energy Inc.'s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The number of common shareholders of record as of Dec. 31, 2015 was approximately 64,202. The following are the intra-day high and low stock prices based on the NYSE Composite Transactions for the quarters of 2015 and 2014 and the dividends declared per share during those quarters. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.'s dividend policy.

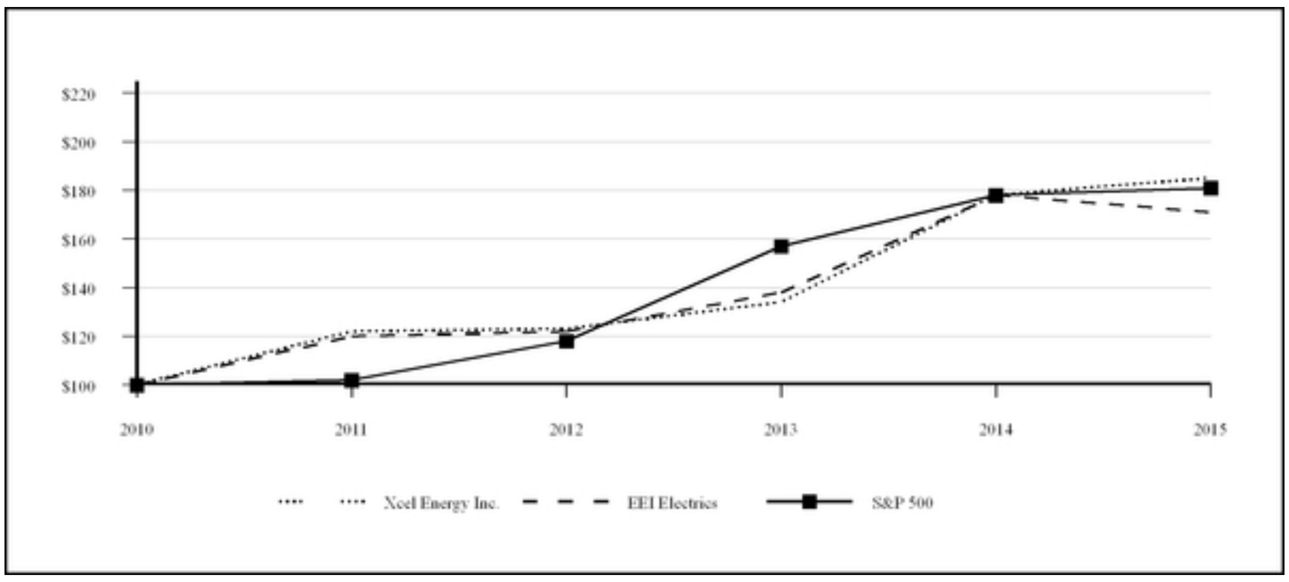
2015	High	Low	Dividends
First quarter	$ 38.35	$ 33.41	$ 0.3200
Second quarter	35.35	31.76	0.3200
Third quarter	36.48	32.12	0.3200
Fourth quarter	37.25	34.33	0.3200

2014	High	Low	Dividends
First quarter	$ 30.77	$ 27.27	$ 0.3000
Second quarter	32.37	29.83	0.3000
Third quarter	32.48	29.60	0.3000
Fourth quarter	37.58	30.18	0.3000

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P's 500 Composite Stock Price Index over the last five years (assuming a $100 investment on Dec. 31, 2010, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) currently includes 46 companies and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*
Among Xcel Energy Inc., the EEI Investor-Owned Electrics
and the S&P 500



* $100 invested on Dec. 31, 2010 in stock or index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2010	2011	2012	2013	2014	2015
Xcel Energy Inc.	$ 100	$ 122	$ 123	$ 134	$ 178	$ 185
EEI Investor-Owned Electrics	100	120	122	138	178	171
S&P 500	100	102	118	157	178	181

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the year ended Dec. 31, 2015:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2015 — Jan. 31, 2015 [(a)]	12,051	$ 37.85	—	—
Feb. 1, 2015 — Feb. 28, 2015	—	—	—	—
March 1, 2015 — March 31, 2015 [(b)]	19,441	$ 34.75	—	—
April 1, 2015 — Dec. 31, 2015	—	—	—	—
Total	31,492		—	—

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

(b) Xcel Energy Inc. withholds stock to satisfy tax withholding obligations on vesting of awards of restricted stock under the Xcel Energy Executive Annual Incentive Award Plan.

Item 6 — Selected Financial Data

Set forth below is selected financial data for Xcel Energy related to the most five recent years ended Dec. 31. This information has been derived from and should be read in conjunction with the consolidated financial statements and notes appearing elsewhere in this annual report on Form 10-K.

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2015	2014	2013	2012	2011
Operating revenues	$ 11,025	$ 11,686	$ 10,915	$ 10,128	$ 10,655
Operating expenses	9,024	9,738	9,067	8,306	8,873
Net income	984	1,021	948	905	841
Earnings available to common shareholders	984	1,021	948	905	834
Weighted average common shares outstanding:					
Basic	507,768	503,847	496,073	487,899	485,039
Diluted	508,168	504,117	496,532	488,434	485,615
EPS:					
Basic	$ 1.94	$ 2.03	$ 1.91	$ 1.86	$ 1.72
Diluted	1.94	2.03	1.91	1.85	1.72
Dividends declared per common share	1.28	1.20	1.11	1.07	1.03
Total assets	39,054	36,958	33,907	31,141	29,497
Long-term debt [(a)]	12,491	11,500	10,911	10,144	8,849
Book value per share	20.89	20.20	19.21	18.19	17.44
Return on average common equity	9.5%	10.3%	10.3%	10.4%	10.1%
Ratio of earnings to fixed charges [(b)]	3.2	3.3	3.1	2.8	2.8
Non-GAAP:					
Ongoing earnings [(c)]	$ 1,064	$ 1,021	$ 968	$ 888	$ 841
Ongoing diluted EPS [(c)]	2.09	2.03	1.95	1.82	1.72

(a) Includes capital lease obligations.
(b) See Exhibit 12.01.
(c) See Item 7 for reconciliations of ongoing earnings and diluted EPS to GAAP earnings and diluted EPS.

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

Business Segments and Organizational Overview

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

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

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2015 EPS guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2015 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; 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; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

Management’s Strategic Plans

Xcel Energy strives to provide our investors an attractive total return and our customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via four key strategic priorities:

- Improving utility performance;
- Driving operational excellence;
- Improving customer experience; and
- Investing for the future.

Below is a discussion of these objectives.

Improving utility performance

Xcel Energy is made up of several utility operating companies. As part of the regulatory process, each state will generally establish an authorized ROE. In many states, our utility operating companies earn less than the authorized ROE due to numerous factors including the timing of implementation of new rates, timing of capital investments, a regulatory commission not allowing the recovery of certain costs, the time period used as a test year for rate cases, fluctuations in sales, the impact of weather, unanticipated cost increases, etc. The difference between the authorized return and what is actually earned is referred to as an ROE gap. Xcel Energy is focused on reducing this gap over the next several years with specific goals as follows:

- Close the regulated ROE gap by 50 basis points by 2018 from the 2014 base level; and
- Derive 75 percent of our revenue from regulated operations via multi-year regulatory plans by 2017.

We continue to pursue regulatory and legislative changes to streamline rate case proceedings and optimize recovery, while improving our alignment with state policies and keeping pace with evolving customer preferences.

Driving operational excellence

Providing safe, reliable service to our customers has, and will continue to be, a fundamental priority. Keeping our costs competitive is also essential in terms of customer affordability, business results and sustained company success over time. To more closely align O&M expense growth with projected sales growth, Xcel Energy is working to limit the increase in annual O&M expense to zero to two percent without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow.

Improving customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Adapting to this changing environment is critical to our long-term success. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price. Our continued investments in clean energy is an example of this commitment to our customers. Environmental stewardship remains foundational to Xcel Energy and is designed to meet customer and policy maker expectations while creating shareholder value. We will continue to offer and expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs.

Investing for the future

Sound investments today are necessary for tomorrow’s success. Our base capital expenditures are projected to be approximately $15.2 billion from 2016 through 2020. This capital forecast will grow rate base at a compounded average annual rate of approximately 3.7 percent, after reflecting the impact of the five year extension of bonus depreciation. Our capital investment plan includes continuing investments in transmission, adding new generation, reducing emissions in our power plants, refreshing our infrastructure, improving reliability, replacing natural gas pipelines and increasing the levels of renewable energy on our system. In addition, Xcel Energy has potential incremental capital investments opportunities that could increase the base capital forecast by an additional $2.5 billion over the 2016-2020 timeframe. The potential incremental investment opportunities include renewables from the NSP System resource plan, renewables in Colorado as part of the “Our Energy Future” Plan, distribution grid modernization, natural gas reserves in Colorado and other investments. This would result in a total capital forecast of $17.7 billion for 2016-2020 and a rate base growth rate of 5.5 percent, after reflecting the impact of the five year extension of bonus depreciation.

Xcel Energy has a proven track record of making sound investments. We proactively made the decision to balance our generation portfolio and expand our alternative energy production. Our customers, stakeholders and the environment are currently benefiting from these decisions and will continue to do so in the future.

Providing an attractive total return

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver an attractive total return for our shareholders. Through a combination of earnings growth and dividend yield, we plan to:

- Deliver long-term annual EPS growth of four percent to six percent, based on ongoing 2015 EPS of $2.10, which was the mid-point of Xcel Energy’s 2015 ongoing guidance range;
- Deliver annual dividend increases of five percent to seven percent (prior objective was two to four percent annually);
- Target a dividend payout ratio of 60 to 70 percent of annual ongoing EPS; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

We have successfully achieved our prior financial objectives, meeting or exceeding our earnings guidance range for eleven consecutive years and believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 6.2 percent and our dividend has grown approximately 4.1 percent annually from 2005 through 2015. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range.

Financial Review

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

The only equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary as well as the ROE of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS and ongoing ROE for Xcel Energy and by subsidiary are financial measures not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity’s average common stockholders’ or stockholder’s equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	2015	2014	2013
PSCo	$ 0.92	$ 0.90	$ 0.91
NSP-Minnesota	0.85	0.80	0.79
SPS	0.25	0.26	0.23
NSP-Wisconsin	0.15	0.14	0.12
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.04
Regulated utility	2.21	2.14	2.09
Xcel Energy Inc. and other	(0.11)	(0.11)	(0.14)
Ongoing diluted EPS [a]	**2.09**	**2.03**	**1.95**
Loss on Monticello LCM/EPU project	(0.16)	—	—
SPS FERC complaint case orders	—	—	(0.04)
GAAP diluted EPS [a]	**$ 1.94**	**$ 2.03**	**$ 1.91**

(a) Amounts may not add due to rounding.

Ongoing earnings exclude adjustments for certain items. For 2015, the adjustment to GAAP earnings is related to the Monticello nuclear facility LCM/EPU project. For 2013, the adjustment is related to the SPS FERC complaint case orders. See below for further discussion of the 2015 and 2013 adjustments and Note 12 to the consolidated financial statements for further discussion of the 2015 and 2013 adjustments.

Xcel Energy’s management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy’s fundamental core earnings power. Xcel Energy’s management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

2015 Adjustment to GAAP Earnings

***Loss on Monticello LCM/EPU Project* —** In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment for 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million, or $79 million net of tax, in the first quarter of 2015. See Note 12 to the consolidated financial statements for further discussion.

2013 Adjustment to GAAP Earnings

***SPS FERC Orders* —** As a result of orders issued in August 2013 by the FERC for a SPS customer refund, a pre-tax charge of $36 million was recorded in 2013. Of this amount, approximately $30 million ($26 million revenue reduction and $4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, GAAP earnings include the total after tax amount of $24.4 million and ongoing earnings exclude $20.2 million. See Note 12 to the consolidated financial statements for further discussion.

Earnings Adjusted for Certain Items (Ongoing EPS)

2015 Comparison with 2014

***Xcel Energy* —** Overall, ongoing earnings increased $0.06 per share for 2015, which excludes an adjustment for a charge related to NSP-Minnesota’s Monticello LCM/EPU project. Ongoing earnings increased primarily due to rate increases in various jurisdictions, non-fuel riders, a lower earnings test refund in Colorado and a decline in operating and maintenance expenses. These positive factors were partially offset by the impact of negative weather as well as higher depreciation, property taxes, interest charges and lower AFUDC.

***PSCo* —** PSCo’s ongoing earnings increased $0.02 per share for 2015. Higher revenue primarily due to the CACJA rider (partially offset by an electric base rate decrease), as well as a natural gas rate increase (interim, subject to refund) effective in October 2015, lower estimated electric earnings test refunds and the positive impact of weather. These positive factors were partially offset by higher property taxes, depreciation, O&M expenses, interest charges and lower AFUDC.

NSP-Minnesota — NSP-Minnesota’s ongoing earnings increased $0.05 per share for 2015. Ongoing earnings were positively impacted by electric rate increases in Minnesota, North Dakota and South Dakota, and lower O&M expenses. These positive factors were partially offset by unfavorable weather, sales decline, higher depreciation, increased interest charges, property taxes and lower AFUDC.

SPS — SPS’ ongoing earnings decreased $0.01 per share for 2015. Although Texas electric rates rose as a result of the prior year rate case, this was reduced by the negative impact of the 2015 case. The net increase in electric rates was more than offset by additional depreciation, higher O&M expenses and lower AFUDC.

NSP-Wisconsin — NSP-Wisconsin’s ongoing earnings increased $0.01 per share for 2015. Higher electric revenues primarily driven by an electric rate increase and lower O&M expenses were partially offset by higher depreciation and lower natural gas margins.

2014 Comparison with 2013

Xcel Energy — Overall, ongoing earnings increased $0.08 per share for 2014. Ongoing earnings increased as a result of higher electric and natural gas margins due to rate increases in various jurisdictions, weather-normalized sales growth and lower interest charges. These positive factors were partially offset by the unfavorable impact of milder weather, as well as higher expected O&M expenses, property taxes and depreciation. 2013 GAAP earnings include a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013. This item was excluded from 2013 ongoing earnings.

PSCo — PSCo’s ongoing earnings decreased $0.01 per share for 2014. Higher natural gas and electric margins primarily due to rate increases, higher AFUDC, lower O&M expenses and weather-normalized sales growth were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.01 per share for 2014. Ongoing earnings were positively impacted by electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth. These items were partially offset by higher O&M expenses, the unfavorable impact of weather, lower AFUDC, increased property taxes and interest charges.

SPS — SPS' ongoing earnings increased $0.03 per share for 2014. Electric rate increases in Texas and New Mexico and weather-normalized sales growth offset higher O&M and depreciation expenses.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2014. An electric rate increase led to higher electric margin, while weather-normalized sales growth positively impacted both electric and natural gas margins. These increases were partially offset by additional O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by $0.03 per share for 2014, largely due to lower financing costs as a result of the refinancing of junior subordinated notes.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014.

Diluted Earnings (Loss) Per Share	**Dec. 31**
2014 GAAP and ongoing diluted EPS	**$ 2.03**
Components of change — 2015 vs. 2014	
Higher electric margins	0.31
Lower conservation and DSM program expenses	0.09
Lower O&M expenses	0.01
Higher depreciation and amortization	(0.13)
Lower AFUDC — equity	(0.07)
Higher ETR	(0.06)
Higher taxes (other than income taxes)	(0.06)
Higher interest charges	(0.03)
Other, net	0.01
2015 ongoing diluted EPS [(a)]	**2.09**
Loss on Monticello LCM/EPU project	(0.16)
2015 GAAP diluted EPS [(a)]	**$ 1.94**

(a) Amounts may not add due to rounding.

Diluted Earnings (Loss) Per Share	**Dec. 31**
2013 GAAP diluted EPS	**$ 1.91**
SPS FERC complaint case orders	0.04
2013 ongoing diluted EPS	**1.95**
Components of change — 2014 vs. 2013	
Higher electric margins (excludes impact of SPS FERC complaint case orders)	0.26
Higher natural gas margins	0.06
Lower interest charges (excludes 2013 impact of SPS FERC complaint case orders)	0.01
Higher O&M expenses	(0.07)
Higher taxes (other than income taxes)	(0.06)
Higher depreciation and amortization	(0.05)
Higher conservation and DSM program expenses	(0.05)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Other, net	0.01
2014 ongoing and GAAP diluted EPS	**$ 2.03**

The following table summarizes the ROE for Xcel Energy and its utility subsidiaries:

ROE — 2015	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies [a]	Xcel Energy [a]
2015 ongoing ROE	9.33%	8.72 %	7.56%	10.45 %	8.91 %	10.22 %
Loss on Monticello LCM/ EPU project	—	(1.49)	—	(0.42)	(0.62)	(0.76)
2015 GAAP ROE	9.33%	7.23 %	7.56%	10.03 %	8.29 %	9.46 %

ROE — 2014	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies [a]	Xcel Energy [a]
2014 ongoing and GAAP ROE	9.40%	8.82%	8.88%	10.85%	9.18%	10.33%

(a) Excluding the impact of negative/positive weather, the Operating Companies and Xcel Energy's ongoing ROEs equate to 9.07 percent and 10.40 percent, respectively, for 2015 and 9.06 percent and 10.18 percent, respectively, for 2014.

The following tables provide reconciliations of ongoing to GAAP earnings (net income) and ongoing to GAAP diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2015	2014	2013
Ongoing earnings	$ 1,063.7	$ 1,021.3	$ 968.4
Loss on Monticello LCM/EPU project (2015) and SPS FERC complaint case orders (2013)	(79.2)	—	(20.2)
GAAP earnings	$ 984.5	$ 1,021.3	$ 948.2

Diluted Earnings (Loss) Per Share	2015	2014	2013
Ongoing diluted EPS [a]	$ 2.09	$ 2.03	$ 1.95
Loss on Monticello LCM/EPU project (2015) and SPS FERC complaint case orders (2013)	(0.16)	—	(0.04)
GAAP diluted EPS [a]	$ 1.94	$ 2.03	$ 1.91

(a) Amounts may not add due to rounding.

The following tables summarize the earnings contributions of Xcel Energy's business segments:

(Millions of Dollars)	2015	2014	2013
GAAP income (loss) by segment			
Regulated electric income	$ 921.4	$ 890.5	$ 850.7
Regulated natural gas income	106.0	128.6	123.7
Other income [a]	15.8	59.5	44.6
Xcel Energy Inc. and other costs [a]	(58.7)	(57.3)	(70.8)
Total net income	$ 984.5	$ 1,021.3	$ 948.2

Contributions to Diluted Earnings (Loss) Per Share	2015	2014	2013
GAAP earnings (loss) by segment			
Regulated electric	$ 1.81	$ 1.77	$ 1.71
Regulated natural gas	0.21	0.25	0.25
Other [a]	0.03	0.12	0.09
Xcel Energy Inc. and other costs [a]	(0.11)	(0.11)	(0.14)
Total diluted EPS	$ 1.94	$ 2.03	$ 1.91

(a) Not a reportable segment. Included in all other segment results in Note 17 to the consolidated financial statements.

Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2013 vs. Normal	2014 vs. 2013
HDD	(7.9)%	7.8 %	(14.8)%	6.5%	0.4 %
CDD	6.2	(2.6)	10.3	24.7	(20.3)
THI	(2.3)	(11.9)	14.1	21.8	(24.2)

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2013 vs. Normal	2014 vs. 2013
Retail electric	$ (0.020)	$ 0.010	$ (0.030)	$ 0.088	$ (0.078)
Firm natural gas	(0.018)	0.019	(0.037)	0.021	(0.002)
Total	$ (0.038)	$ 0.029	$ (0.067)	$ 0.109	$ (0.080)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales for the years ended Dec. 31, compared with the previous year:

	2015 vs. 2014				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	1.1 %	(3.2)%	(0.4)%	(6.1)%	(1.4)%
Electric C&I	(0.4)	(0.6)	0.3	0.4	(0.2)
Total retail electric sales	0.1	(1.4)	0.1	(1.5)	(0.6)
Firm natural gas sales	(6.6)	(16.6)	N/A	(16.4)	(10.5)

	2015 vs. 2014				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.4 %	(0.7)%	0.6%	(2.8)%	(0.3)%
Electric C&I	(0.9)	(0.2)	0.7	0.8	(0.1)
Total retail electric sales	(0.5)	(0.4)	0.5	(0.3)	(0.2)
Firm natural gas sales	(2.0)	(1.1)	N/A	(1.7)	(1.7)

(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

Weather-normalized Electric 2015 Growth (Decline)

- PSCo's residential growth was primarily the result of customer additions, partially offset by lower use per customer. Commercial and industrial (C&I) decline was primarily due to reduced sales to certain large manufacturing customers and/or those that support the fracking industry.
- NSP-Minnesota's residential decrease was due to lower use per customer, partially offset by an increase in customer additions. C&I electric sales decreased as a result of lower use by large and small customers (e.g., services, retail trade, finance insurance and real estate industries), partially offset by higher use by certain large customers in the petroleum and food processing industries. The decline was partially reduced by an increase in the number of customers in both the small and large classes.
- SPS' residential growth reflects an increased number of customers. C&I also had an increase in customers, primarily in the oil and gas exploration and production industries. However, this was partially offset by reduced activity per customer within these industries, as well as less irrigation by agricultural customers due to wet weather.
- NSP-Wisconsin's residential decline was primarily attributable to lower use per customer, partially offset by customer additions. C&I electric sales growth was largely due to strong sales to large customers primarily in the oil and gas industries.

Weather-normalized Natural Gas 2015 Decline

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

Weather-normalized sales for 2016 are projected to increase approximately 0.5 percent to 1.0 percent for retail electric customers and remain relatively flat for retail firm natural gas customers.

	2014 v. 2013				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	(2.8)%	(1.6)%	(0.4)%	(0.3)%	(1.8)%
Electric C&I	0.3	—	2.5	4.2	1.0
Total retail electric sales	(0.7)	(0.5)	1.8	2.8	0.2
Firm natural gas sales	(0.7)	7.3	N/A	7.4	2.3

	2014 vs. 2013				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.3%	0.7%	0.4%	0.5%	0.5%
Electric C&I	1.6	0.6	2.8	4.4	1.7
Total retail electric sales	1.2	0.6	2.3	3.3	1.3
Firm natural gas sales	5.2	3.6	N/A	3.8	4.6

(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

Weather-normalized Electric 2014 Growth

- NSP-Wisconsin's electric sales growth was largely due to strong sales to large C&I customers primarily in the oil, gas and sand mining industries.
- SPS' C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area.
- PSCo's electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota's electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas 2014 Growth

- Across our natural gas service territories, strong sales were experienced in 2014, which continued the trend that began in the last half of 2013.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2015	2014	2013
Electric revenues	$ 9,276	$ 9,466	$ 9,034
Electric fuel and purchased power	(3,763)	(4,210)	(4,019)
Electric margin	$ 5,513	$ 5,256	$ 5,015

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

Electric Revenues

(Millions of Dollars)	2015 vs. 2014
Fuel and purchased power cost recovery	$ (469)
Conservation and DSM program revenues (offset by expenses)	(62)
Estimated impact of weather	(23)
Trading	(14)
Retail rate increases [(a)]	101
Colorado CACJA non-fuel rider	94
Transmission revenue	91
PSCo earnings test refund	74
Non-fuel riders [(b)]	20
Other, net	(2)
Total decrease in electric revenues	$ (190)

2015 Comparison with 2014 — Electric revenues decreased primarily due to lower fuel and purchased power cost recovery, which is offset in operating expense. This decrease was partially offset by various rate increases at NSP-Minnesota, NSP-Wisconsin and SPS as well as the non-fuel rider in Colorado.

Electric Margin

(Millions of Dollars)		2015 vs. 2014
Retail rate increases [(a)]	$	101
Colorado CACJA non-fuel rider		94
PSCo earnings test refunds		74
Transmission revenue, net of costs		47
Non-fuel riders [(b)]		20
Conservation and DSM program revenues (offset by expenses)		(62)
Estimated impact of weather		(23)
Other, net		6
Total increase in electric margin	$	257

(a) Increase due to rate proceedings in Minnesota, South Dakota, Texas, North Dakota, New Mexico and Wisconsin. These increases were partially offset by a decline in Colorado retail base rates, which was more than offset by increased CACJA rider revenue as approved by the CPUC in the first quarter of 2015.

(b) Primarily related to the Transmission Cost Recovery rider in Minnesota.

2015 Comparison to 2014 — The increase in electric margin was primarily due to the various rate increases at NSP-Minnesota, NSP-Wisconsin and SPS as well as the non-fuel rider in Colorado.

Electric Revenues

(Millions of Dollars)		2014 vs. 2013
Retail rate increases [(a)]	$	129
Trading		100
Fuel and purchased power cost recovery		78
Non-fuel riders		57
Transmission revenue		48
Conservation and DSM program revenues (offset by expenses)		44
Retail sales growth, excluding weather impact		24
Estimated impact of weather		(60)
Other, net		(14)
Total increase in ongoing electric revenues		406
SPS FERC complaint case orders [(b)]		26
Total increase in GAAP electric revenues	$	432

2014 Comparison with 2013 — Electric revenues increased primarily due to various rate increases across all of the utility subsidiaries, higher trading and increased fuel and purchased power cost recovery, which is offset in operating expense.

Electric Margin

(Millions of Dollars)		2014 vs. 2013
Retail rate increases [a]	$	129
Non-fuel riders		57
Conservation and DSM program revenues (offset by expenses)		44
Transmission revenue, net of costs		31
Retail sales growth, excluding weather impact		24
NSP-Wisconsin fuel recovery		11
Estimated impact of weather		(60)
Firm wholesale		(6)
Other, net		(15)
Total increase in ongoing electric margin		215
SPS FERC complaint case orders [b]		26
Total increase in GAAP electric margin	$	241

(a) The retail rate increases included final rates in Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota, which were subject to and net of estimated provision for refund.

(b) As a result of two orders issued by the FERC in August 2013, a pretax charge of approximately $36 million ($32 million in electric revenues, of which $6 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in 2013.

2014 Comparison to 2013 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

Natural Gas Revenues and Margin

Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

(Millions of Dollars)		2015		2014		2013
Natural gas revenues	$	1,672	$	2,143	$	1,805
Cost of natural gas sold and transported		(905)		(1,372)		(1,083)
Natural gas margin	$	767	$	771	$	722

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

Natural Gas Revenues

(Millions of Dollars)		2015 vs. 2014
Purchased natural gas adjustment clause recovery	$	(462)
Estimated impact of weather		(30)
Conservation and DSM program revenues (offset by expenses)		(13)
Infrastructure and integrity riders, partially offset in O&M expenses		30
Purchased gas adjustment		5
Retail rate increases (Colorado, interim, subject to refund)		4
Other, net		(5)
Total decrease in natural gas revenues	$	(471)

2015 Comparison to 2014 — Natural gas revenues decreased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2015 vs. 2014
Estimated impact of weather	$ (30)
Conservation and DSM program revenues (offset by expenses)	(13)
Infrastructure and integrity riders, partially offset in O&M expenses	30
Purchased gas adjustment	5
Retail rate increases (Colorado, interim, subject to refund)	4
Total decrease in natural gas margin	$ (4)

2015 Comparison to 2014 — Natural gas margins decreased primarily due to warmer winter weather and lower gas recovery rates primarily in NSP-Minnesota and PSCo.

Natural Gas Revenues

(Millions of Dollars)	2014 vs. 2013
Purchased natural gas adjustment clause recovery	$ 293
Retail rate increases (Colorado)	19
PSIA rider (Colorado)	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	3
Total increase in natural gas revenues	$ 338

2014 Comparison to 2013 — Natural gas revenues increased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases (Colorado)	$ 19
PSIA rider (Colorado), partially offset in O&M expenses	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	7
Total increase in natural gas margin	$ 49

2014 Comparison to 2013 — Natural gas margins increased primarily due to rate increases and the PSIA in Colorado.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $4.7 million, or 0.2 percent, for 2015 compared with 2014. The following table summarizes the change in O&M expenses:

(Millions of Dollars)	2015 vs. 2014
Nuclear plant operations	$ (22)
Transmission costs	(4)
Labor and contract labor	14
Plant generation costs	1
Other, net	6
Total decrease in O&M expenses	$ (5)

2015 Comparison to 2014 — The decrease in O&M expenses for 2015 was due to the following:

- Nuclear expense decreased primarily driven by operational efficiencies and lower amortization of prior outages; and
- Labor and contract labor increased as a result of various projects and initiatives to improve business processes.

For 2014 compared with 2013, O&M expenses increased $60.8 million, or 2.7 percent. The following table summarizes the change in O&M expenses:

(Millions of Dollars)	2014 vs. 2013
Nuclear plant operations and amortization	$ 36
2013 gain on sale of transmission assets	14
Transmission costs	4
Electric and natural gas distribution expenses	1
Employee benefits	(6)
Plant generation costs	(3)
Other, net	15
Total increase in O&M expenses	$ 61

***2014 Comparison to 2013* —** The increase in O&M expenses for 2014 was largely driven by the following:

- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants; and
- Gain on sale of transmission assets relates to the 2013 gain associated with the sale of certain SPS' transmission assets to Sharyland.

***Conservation and DSM Program Expenses* —** Conservation and DSM program expenses decreased $77.1 million, or 25.5 percent, for 2015 compared with 2014. The decrease was primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Lower conservation and DSM program expenses are generally offset by lower revenues.

Conservation and DSM program expenses increased $41.0 million, or 15.7 percent, for 2014 compared with 2013. The increase was primarily attributable to higher electric recovery rates at NSP-Minnesota.

***Depreciation and Amortization* —** Depreciation and amortization increased $105.5 million, or 10.4 percent, for 2015 compared with 2014. The increase was primarily attributed to capital investments and lower amortization of the excess depreciation reserve in Minnesota, partially offset by Minnesota's amortization of the DOE settlement.

Depreciation and amortization increased $41.2 million, or 4.2 percent, for 2014 compared with 2013. The increase was primarily attributable to the PI steam generator replacement placed in service in December 2013 and normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets.

***Taxes (Other Than Income Taxes)* —** Taxes (other than income taxes) increased $45.8 million, or 9.8 percent, for 2015 compared with 2014. The increase was due to higher property taxes primarily in Colorado and Minnesota.

Taxes (other than income taxes) increased $45.3 million, or 10.8 percent, for 2014 compared with 2013. The increase was primarily due to higher property taxes in Colorado, Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC decreased $46.0 million for 2015 compared with 2014. The decrease was primarily due to the implementation of the CACJA rider, facilitating earlier and alternative recovery of construction costs.

AFUDC increased $1.3 million for 2014 compared with 2013. The increase was primarily due to construction related to the CACJA and the expansion of transmission facilities, partially offset by the portion of the Monticello LCM/EPU placed in service in July 2013 and the PI steam generator replacement placed in service in December 2013.

***Interest Charges* —** Interest charges increased $28.7 million, or 5.1 percent, for 2015 compared with 2014. The increase was primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Interest charges decreased $8.6 million, or 1.5 percent, for 2014 compared with 2013. The decrease was primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels. In addition, interest charges in 2013 reflected $4 million of interest associated with the customer refund at SPS based on a FERC order, interest on customer refunds in Minnesota and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Income Taxes — Income tax expense increased $18.9 million for 2015 compared with 2014. The increase was primarily due to a higher tax benefit for a carryback claim in 2014 and decrease in permanent plant-related deductions (e.g., AFUDC-equity) in 2015. The ETR was 35.5 percent for 2015 compared with 33.9 percent for 2014. See Note 6 to the consolidated financial statements for further discussion.

Income tax expense increased $39.8 million for 2014 compared with 2013. The increase was primarily due to higher 2014 pretax earnings and recognition of additional R&E credits in 2013. These were partially offset by a 2014 tax benefit for prior year adjustments. The ETR was 33.9 percent for 2014 compared with 33.8 percent for 2013. See Note 6 to the consolidated financial statements for further discussion.

Xcel Energy Inc. and Other Results

The following tables summarize the net income and EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution to Xcel Energy's Earnings		
(Millions of Dollars)	**2015**	**2014**	**2013**
Xcel Energy Inc. financing costs	$ (56.1)	$ (51.8)	$ (62.9)
Eloigne [(a)]	0.1	(0.5)	(0.8)
Xcel Energy Inc. taxes and other results	(2.7)	(5.0)	(7.1)
Total Xcel Energy Inc. and other costs	$ (58.7)	$ (57.3)	$ (70.8)

	Contribution to Xcel Energy's EPS		
(Earnings per Share)	**2015**	**2014**	**2013**
Xcel Energy Inc. financing costs	$ (0.11)	$ (0.10)	$ (0.13)
Eloigne [(a)]	—	—	—
Xcel Energy Inc. taxes and other results	—	(0.01)	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.11)	$ (0.11)	$ (0.14)

(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

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

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. While economic growth has been improving over the past year, management cannot predict whether this trend will be sustained going forward. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Fuel Supply and Costs

Xcel Energy Inc.'s operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax or emissions-related generation restrictions and unanticipated changes in regulatory recovery mechanisms could impact our operations. See Item 1 for further discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see “Employee Benefits” under Critical Accounting Policies and Estimates.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.’s utility subsidiaries and TransCo 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 Inc.’s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Rates charged by Xcel Energy Inc.’s TransCo subsidiaries and WGI are approved by the FERC. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Changes in operating costs can affect Xcel Energy’s financial results, depending on the timing of filing general rate cases and the implementation of final rates. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings.

Wholesale Energy Market Regulation — Wholesale energy markets in the Midwest and South Central U.S. are operated by MISO and SPP, respectively, to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. NSP-Minnesota and NSP-Wisconsin are members of MISO and SPS is a member of SPP. NSP-Minnesota, NSP-Wisconsin and SPS expect to recover energy charges through either base rates or various recovery mechanisms. See Note 12 to the consolidated financial statements for further discussion.

Capital Expenditure Regulation — Xcel Energy Inc.’s utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filings for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC, MPUC, SDPUC, NDPSC and PUCT in certain instances have approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, increase transmission investment cost, and/or increase distribution investment cost, and increase purchased power capacity cost. These non-fuel rate riders are expected to provide cash flows to enable recovery of costs incurred on a more timely basis. For wholesale electric transmission and production services, Xcel Energy has, consistent with FERC policy, implemented formula rates for each of the utility subsidiaries that will provide annual rate changes as transmission or production investments increase in a manner similar to the retail rate riders. In November 2014, the FERC approved transmission formula rates for XETD and XEST, which would apply to electric transmission assets the TransCos may own. NSP-Minnesota and NSP-Wisconsin have no cost-based wholesale production customers and therefore have not implemented a production formula rate.

Environmental Matters

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

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

- $292 million in 2015;
- $292 million in 2014; and
- $275 million in 2013.

Xcel Energy estimates an average annual expense of approximately $338 million from 2016 through 2020 for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $184 million in 2015;
- $373 million in 2014; and
- $517 million in 2013.

See Item 7 — Capital Requirements for further discussion.

Xcel Energy's operations are subject to federal and state laws and regulations related to air emissions, water discharges and waste management from various sources. Such laws and regulations impose monitoring and reporting requirements and may require Xcel Energy to obtain pre-approval for the construction or modification of projects that increase air emissions, water discharges or land disposal of wastes, obtain and comply with permits that contain emission, discharge and operational limitations, or install or operate pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation of MGP and other legacy sites and various regulations for air emissions, water intake and discharge and waste disposal. Actual expenditures could vary from the estimates presented. The scope and timing of these expenditures cannot be determined until any new or revised regulations become final or until more information is learned about the need for remediation at the legacy sites.

Pollution control equipment can be required by federal and state regulations, such as those requiring mercury emission reductions, and by state or federal implementation plans, such as those to address visibility impairment, interstate air pollution impacts or attainment of NAAQS. Xcel Energy has installed and is operating control equipment needed to comply with the requirements of the federal Mercury and Air Toxic Standards Rule. Most recently, the EPA has adopted a federal visibility plan for Texas which imposes SO_2 emission limitations that reflect installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by early 2021.

See Note 13 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation could result from economic conditions or the economic and monetary policies of the U.S. Government and the Federal Reserve. This could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers. If current low oil prices lead to sustained deflation, that could also reduce general economic activity although it may lead to lower electric and natural gas prices to customers.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported. The following is a list of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy Inc. is a holding company with rate-regulated subsidiaries that are subject to the accounting for Regulated Operations*,* which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if the competitive environment makes it probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or OCI.

Each reporting period Xcel Energy assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact Xcel Energy's results of operations, financial condition or cash flows.

As of Dec. 31, 2015 and 2014, Xcel Energy has recorded regulatory assets of $3.2 billion and regulatory liabilities of $1.6 billion. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets. See Note 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities and Note 12 to the consolidated financial statements for further discussion of rate matters.

Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR. Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our ETR in the future. There exists the potential for federal tax reform that may significantly change the tax rules applicable to Xcel Energy. At this time, due to the inherent uncertainty of future legislation, any potential resulting impact cannot be reasonably estimated.

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

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates including forecasted annual income, permanent tax adjustments and tax credits.

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

We may adjust our unrecognized tax benefits and interest accruals to the updated estimates as disputes with the IRS and state tax authorities are resolved. These adjustments may increase or decrease earnings. See Note 6 to the consolidated financial statements for further discussion.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension and postretirement health care investment assets are expected to earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation. In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. See Note 9 to the consolidated financial statements for further discussion on the rate of return and discount rate used in the calculation of pension costs and obligations.

Pension costs are expected to decrease in 2016 and continue to decline in the following few years. Funding requirements increased in 2016 and then be flat in the following years. While investment returns exceeded the assumed levels in 2014, investment returns were below the assumed levels in 2013 and 2015. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees which was approximately 11 years in 2015.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $120.7 million in 2016 and $117.0 million in 2017, while the actual pension costs were $127.7 million in 2015 and $126.5 million in 2014. The expected decrease in 2016 costs is due primarily to the reduction in historic loss amortization amounts including the 2008 market loss and an increase in the discount rate, which were offset by current year asset losses and a lowering of the expected return on asset assumption. Further, future year costs are expected to decrease primarily as a result of reductions in loss amortizations and an increase in expected return on assets due to planned future contributions and expected return of current assets.

In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on our population and specific experience. Further, at year-end 2015, Xcel Energy evaluated the updated projection table, MP 2015, and concluded that the methodology adopted at the end of 2014 is consistent with the new projection table and continues to be representative of Xcel Energy's population. Therefore, no changes are required.

At Dec. 31, 2015, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87 percent, which is a 22 basis point decrease from Dec. 31, 2014. The rate of return used to measure postretirement health care costs is 5.80 percent at Dec. 31, 2015 and this is consistent with Dec. 31, 2014. Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the Dec. 31, 2015 pension and postretirement health care obligations at 4.66 percent and 4.65 percent, which represent a 55 basis point and 57 basis point increase from Dec. 31, 2014, respectively. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration. The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Citigroup Pension Liability Discount Curve and the Citigroup Above Median Curve. At Dec. 31, 2015, these reference points supported the selected rate. In addition to these reference points, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The following are the pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2013 through 2016:

- $125.0 million in January 2016;
- $90.1 million in 2015;

- $130.6 million in 2014; and
- $192.4 million in 2013.

For future years, we anticipate contributions will be made as necessary. These contributions are summarized in Note 9 to the consolidated financial statements. Future year amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2015, a one-percent change would result in the following impact on 2016 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (20.5)	$ 20.9
Discount rate [(a)]	(8.6)	10.9

[(a)] These costs include the effects of regulation.

Effective Jan. 1, 2016, the initial medical trend assumption decreased from 6.50 percent to 6.00 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed $18.3 million, $17.1 million and $17.6 million during 2015, 2014 and 2013, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately $12.3 million during 2016.

Xcel Energy recovers employee benefits costs in its regulated utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions as calculated using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Texas and Colorado electric retail jurisdictions, and commencing in 2016, the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.

See Note 9 to the consolidated financial statements for further discussion.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions used to estimate AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset. Xcel Energy accretes ARO liabilities to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The total obligation for nuclear decommissioning is expected to be funded 100 percent by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized under current accounting guidance is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.141 billion and $2.038 billion as of Dec. 31, 2015 and 2014, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. These independent cost studies are based on relevant information available at the time performed. Estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning study every three years. In December 2014, NSP-Minnesota submitted this filing to the MPUC, which covered all expenses over the decommissioning period of the nuclear plants, including decontamination and removal of radioactive material. The MPUC approved the study in October 2015.

The following key assumptions have a significant effect on the estimated nuclear obligation:

- Timing — Decommissioning cost estimates are impacted by each facility's retirement date and the expected timing of the actual decommissioning activities. Currently, the estimated retirement dates coincide with each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which is required by the MPUC. By utilizing this method, which assumes prompt removal and dismantlement, these activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

- Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's 2014 nuclear decommissioning filing assumed current technology and regulations.

- Escalation Rates — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 4.36 percent in calculating the AROs related to nuclear decommissioning for the remaining operational period through the radiological decommissioning period. An escalation rate of 3.36 percent was utilized for the period of operating costs related to interim dry cask storage of spent nuclear fuel and site restoration.

- Discount Rates — Changes in timing or estimated expected cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately four and seven percent have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating the future cost of nuclear decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially. However, changes in estimates should have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2015.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse 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. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

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

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

At Dec. 31, 2015, the fair values by source for net commodity trading contract assets were as follows:

		Futures / Forwards				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota	1	$ 2,699	$ 5,959	$ 1,575	$ —	$ 10,233
NSP-Minnesota	2	695	—	—	—	695
PSCo	1	128	(16)	—	—	112
		$ 3,522	$ 5,943	$ 1,575	$ —	$ 11,040

1 — Prices actively quoted or based on actively quoted prices.
2 — Prices based on models and other valuation methods.

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

(Thousands of Dollars)	2015	2014
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 21,811	$ 30,514
Contracts realized or settled during the period	(3,578)	(12,698)
Commodity trading contract additions and changes during the period	(7,193)	3,995
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 11,040	$ 21,811

At Dec. 31, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.3 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.3 million. At Dec. 31, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.9 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.9 million.

Xcel Energy Inc.'s utility subsidiaries' 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, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2015	$ 0.10	$ 3.00	$ 0.28	$ 1.34	$ 0.06
2014	0.57	3.00	0.61	4.06	0.13

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 46 percent of its 2016 and approximately 16 percent of its 2017 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 35 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material beyond 2016.

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

At Dec. 31, 2015 and 2014, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $8.5 million and $10.4 million, respectively. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2015, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

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

At Dec. 31, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $1.9 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $6.1 million. At Dec. 31, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $12.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2.7 million.

Xcel Energy Inc. 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. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 11 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2015. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2015.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 1.3 percent and 12.2 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2015.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $22.7 million and $4.6 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2015.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 forwards or options held at Dec. 31, 2015.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $242.3 million in the nuclear decommissioning fund at Dec. 31, 2015 (approximately 13.6 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2015	2014	2013
Net cash provided by operating activities	$ 3,026	$ 2,648	$ 2,584

Net cash provided by operating activities increased by $378 million for 2015 as compared to 2014. The increase was primarily due to rate increases in various jurisdictions, higher customer refunds in 2014 and income tax refunds received in 2015 compared to taxes paid in 2014, partially offset by refunds issued as part of a settlement agreement with Golden Spread and PNM in 2015.

Net cash provided by operating activities increased by $64 million for 2014 as compared to 2013. Additional net income, excluding amounts related to non-cash operating activities (e.g. depreciation and deferred tax expenses) and lower pension contributions in 2014 were offset by changes in working capital and other noncurrent assets and liabilities.

(Millions of Dollars)	2015	2014	2013
Net cash used in investing activities	$ (3,623)	$ (3,117)	$ (3,213)

Net cash used in investing activities increased by $506 million for 2015 as compared to 2014. The increase was primarily attributable to the acquisition of two wind projects in 2015, partially offset by higher insurance proceeds related to Sherco Unit 3 received in 2015.

Net cash used in investing activities decreased by $96 million for 2014 as compared to 2013. The decrease was primarily attributable to higher capital expenditures in 2013 associated with several major construction projects including the Monticello nuclear EPU and the PI steam generator replacement. The change in capital expenditures was partially offset by the impact of higher insurance proceeds related to Sherco Unit 3 and proceeds received from the sale of certain transmission assets to Sharyland in 2013.

(Millions of Dollars)	2015	2014	2013
Net cash provided by financing activities	$ 602	$ 442	$ 654

Net cash provided by financing activities increased by $160 million for 2015 as compared to 2014. The increase was primarily due to higher debt issuances, partially offset by repayments of short-term debt in 2015 compared to proceeds in 2014 and the impact of less common stock issuances in 2015.

Net cash provided by financing activities decreased by $212 million for 2014 as compared to 2013. The decrease was primarily due to lower proceeds from long-term debt, less issuances of common stock and higher dividend payments, partially offset by higher proceeds from short-term debt and lower repayments of long-term debt.

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

Capital Requirements

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

Capital Expenditures — The actual and current estimated base capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2020 are shown in the table below.

	Actual	Base Capital Forecast					
(Millions of Dollars)	2015	2016	2017	2018	2019	2020	2016 - 2020 Total
By Subsidiary							
NSP-Minnesota	$ 1,753	$ 1,290	$ 1,050	$ 1,215	$ 1,245	$ 1,125	$ 5,925
PSCo	944	975	940	960	1,030	1,070	4,975
SPS	602	560	725	640	520	450	2,895
NSP-Wisconsin	230	225	250	295	265	285	1,320
Other	—	10	10	10	10	10	50
Total capital expenditures	$ 3,529	$ 3,060	$ 2,975	$ 3,120	$ 3,070	$ 2,940	$ 15,165

(Millions of Dollars)	Actual 2015	Base Capital Forecast 2016	2017	2018	2019	2020	2016 - 2020 Total
By Function							
Electric transmission	$ 889	$ 700	$ 825	$ 875	$ 855	$ 870	$ 4,125
Electric distribution	639	645	775	790	915	940	4,065
Electric generation	1,230	835	510	565	470	465	2,845
Natural gas	368	390	335	395	390	400	1,910
Nuclear fuel	90	120	120	60	145	85	530
Minnesota Integrated Resource Plan renewables	—	—	120	250	110	—	480
Other	313	370	290	185	185	180	1,210
Total capital expenditures	$ 3,529	$ 3,060	$ 2,975	$ 3,120	$ 3,070	$ 2,940	$ 15,165

In addition, Xcel Energy has potential incremental capital investment opportunities that could increase the base capital forecast by $2.5 billion over the 2016-2020 timeframe. The potential incremental investment opportunities include renewables from the NSP System resource plan, renewables in Colorado as part of the "Our Energy Future" plan, distribution grid modernization, natural gas reserves in Colorado and other investments. This would result in a total capital forecast of $17.7 billion for 2016-2020.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy's TransCos.

Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Xcel Energy does not anticipate issuing any equity to fund its base capital investment program for 2016-2020. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2016 through 2020 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$ 13,280
New Debt**	1,885
Equity	—
2016-2020 Capital Expenditures	$ 15,165
Maturing Debt	$ 4,165

* Net of dividend and pension funding.
** Reflects a combination of short and long-term debt.

Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2015. See the statements of capitalization and additional discussion in Notes 4 and 13 to the consolidated financial statements.

	Payments Due by Period				
(Thousands of Dollars)	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**After 5 Years**
Long-term debt, principal and interest payments [a]	$ 21,797,721	$ 1,227,067	$ 2,897,756	$ 2,547,661	$ 15,125,237
Capital lease obligations	334,461	17,135	29,722	28,842	258,762
Operating leases [b][c]	3,529,682	241,572	462,152	515,767	2,310,191
Unconditional purchase obligations [d]	8,523,291	1,801,881	2,088,242	1,220,206	3,412,962
Other long-term obligations, including current portion [e]	322,687	93,698	153,719	75,270	—
Payments to vendors in process	32,547	32,547	—	—	—
Short-term debt	846,000	846,000	—	—	—
Total contractual cash obligations [f][g][h]	$ 35,386,389	$ 4,259,900	$ 5,631,591	$ 4,387,746	$ 21,107,152

(a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2015, and outstanding principal for each investment with the terms ending at each instrument's maturity.

(b) 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, 2015, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $61.0 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(c) Included in operating lease payments are $217.0 million, $418.7 million, $469.1 million and $2.1 billion, for the less than 1 year, 1-3 years, 3-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

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

(e) Other long-term obligations relate primarily to amounts associated with technology agreements and approximate investments in Energy Impact Fund LP, as well as uncertain tax positions.

(f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately $3.2 billion of goods and services through the year 2053, in addition to the amounts disclosed in this table.

(g) In January 2016, contributions of $125.0 million were made across four of Xcel Energy's pension plans. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

(h) Xcel Energy expects to contribute approximately $12.3 million to the postretirement health care plans during 2016. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

Common Stock Dividends **—** Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. Xcel Energy's financial objectives include: growing annual ongoing EPS four percent to six percent, growing the annual dividend five percent to seven percent and targeting a dividend payout ratio of 60 percent to 70 percent of annual ongoing EPS. On Feb. 17, 2016, Xcel Energy announced a quarterly dividend of $0.34 per share, which represented an increase of 6.3 percent. Xcel Energy's dividend policy balances:

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

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

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See Note 4 to the consolidated financial statements for further discussion of restrictions on dividend payments.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the CFTC and the SEC with expanded regulatory authority over derivative and swap transactions. The CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to $3 billion in 2017. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy's Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy is currently meeting all reporting requirements and transaction restrictions.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income and interest rate swap securities, and alternative investments, including private equity, real estate, hedge funds and commodity investments.

The funded status and pension assumptions are summarized in the following tables:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Fair value of pension assets	$ 2,884	$ 3,084
Projected pension obligation [(a)]	3,568	3,747
Funded status	$ (684)	$ (663)

(a) Excludes nonqualified plan of $42 million and $47 million at Dec. 31, 2015 and 2014, respectively.

Pension Assumptions	2015	2014
Discount rate	4.66%	4.11%
Expected long-term rate of return	6.87	7.09

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Dec. 31, 2015 and 2014, there was $3.3 million of cash held in these accounts.

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

- $1 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	$ 2,750
Amount outstanding at period end	846
Average amount outstanding	290
Maximum amount outstanding	846
Weighted average interest rate, computed on a daily basis	0.56%
Weighted average interest rate at end of period	0.82

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013
Borrowing limit	$ 2,750	$ 2,750	$ 2,450
Amount outstanding at period end	846	1,020	759
Average amount outstanding	601	841	481
Maximum amount outstanding	1,360	1,200	1,160
Weighted average interest rate, computed on a daily basis	0.48%	0.33%	0.31%
Weighted average interest rate at end of period	0.82	0.56	0.25

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.75 billion and each credit facility terminates in October 2019.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 17, 2016, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,000	$ 616	$ 384	$ —	$ 384
PSCo	700	4	696	1	697
NSP-Minnesota	500	250	250	1	251
SPS	400	65	335	1	336
NSP-Wisconsin	150	—	150	3	153
Total	$ 2,750	$ 935	$ 1,815	$ 6	$ 1,821

(a) These credit facilities mature in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2015 and 2014, Xcel Energy Inc. had approximately 508 million shares and 506 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of seven million shares of $100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2015 and 2014.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Financing Plans — During 2016, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $700 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $250 million of first mortgage bonds; and
- SPS plans to issue approximately $350 million of first mortgage bonds.

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

Long-Term Borrowings and Other Financing Instruments — See the consolidated statements of capitalization and a discussion of the long-term borrowings in Note 4 to the consolidated financial statements.

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025;
- NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- SPS issued $200 million of 3.3 percent first mortgage bonds due June 15, 2024.

Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an ATM program for approximately $175 million during the first six months of 2014. Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity over the next five years based on its current capital expenditure plan.

Income Tax — In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides varying extensions of bonus depreciation, PTCs, ITCs, and the R&E credit. The impact of these items will vary based on the amount and timing of investment, level of production, and the amount of qualifying expenditures. See Note 6 to the consolidated financial statements for further discussion.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy’s 2016 ongoing earnings guidance is $2.12 to $2.27 per share. Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent to 1.0 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $70 million to $80 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $200 million over 2015 levels.
- Property taxes are projected to increase approximately $40 million to $50 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2015 levels.
- AFUDC — equity is projected to decline approximately $10 million to $15 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on ongoing 2015 EPS of $2.10, which was the mid-point of Xcel Energy’s 2015 ongoing guidance range;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management’s view, not reflective of ongoing operations.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

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

See Note 18 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'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 Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2015. 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 (2013).* Based on our assessment, we believe that, as of Dec. 31, 2015, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE	/s/ TERESA S. MADDEN
Ben Fowke	Teresa S. Madden
Chairman, President and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 19, 2016	Feb. 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholders' equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* 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, 2015 of the Company and our report dated February 19, 2016 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 19, 2016

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2015	2014	2013
Operating revenues			
Electric	$ 9,275,986	$ 9,465,890	$ 9,034,045
Natural gas	1,672,081	2,142,738	1,804,679
Other	76,419	77,507	76,198
Total operating revenues	11,024,486	11,686,135	10,914,922
Operating expenses			
Electric fuel and purchased power	3,762,953	4,210,142	4,018,672
Cost of natural gas sold and transported	904,794	1,372,479	1,082,751
Cost of sales — other	36,216	34,352	33,323
Operating and maintenance expenses	2,329,670	2,334,379	2,273,532
Conservation and demand side management program expenses	224,679	301,772	260,726
Depreciation and amortization	1,124,524	1,019,045	977,863
Taxes (other than income taxes)	511,675	465,836	420,500
Loss on Monticello life cycle management/extended power uprate project	129,463	—	—
Total operating expenses	9,023,974	9,738,005	9,067,367
Operating income	2,000,512	1,948,130	1,847,555
Other income, net	5,400	5,296	2,972
Equity earnings of unconsolidated subsidiaries	34,390	30,151	30,020
Allowance for funds used during construction — equity	55,936	89,750	87,683
Interest charges and financing costs			
Interest charges — includes other financing costs of $24,175, $22,986 and $30,135, respectively	595,282	566,608	575,199
Allowance for funds used during construction — debt	(26,248)	(38,402)	(39,179)
Total interest charges and financing costs	569,034	528,206	536,020
Income before income taxes	1,527,204	1,545,121	1,432,210
Income taxes	542,719	523,815	483,976
Net income	$ 984,485	$ 1,021,306	$ 948,234
Weighted average common shares outstanding:			
Basic	507,768	503,847	496,073
Diluted	508,168	504,117	496,532
Earnings per average common share:			
Basic	$ 1.94	$ 2.03	$ 1.91
Diluted	1.94	2.03	1.91
Cash dividends declared per common share	$ 1.28	$ 1.20	$ 1.11

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Net income	$ 984,485	$ 1,021,306	$ 948,234
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical benefit (losses) gains arising during the period, net of tax of $(5,026), $(4,687), and $1,746, respectively	(7,906)	(7,517)	1,408
Amortization of losses included in net periodic benefit cost, net of tax of $2,249, $2,159, and $4,151, respectively	3,526	3,495	3,306
	(4,380)	(4,022)	4,714
Derivative instruments:			
Net fair value (decrease) increase, net of tax of $(46), $(103), and $17, respectively	(70)	(163)	12
Reclassification of losses to net income, net of tax of $1,810, $1,493, and $2,541, respectively	2,836	2,288	1,476
	2,766	2,125	1,488
Marketable securities:			
Net fair value increase, net of tax of $0, $21, and $117, respectively	—	33	176
Other comprehensive (loss) income	(1,614)	(1,864)	6,378
Comprehensive income	$ 982,871	$ 1,019,442	$ 954,612

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating activities			
Net income	$ 984,485	$ 1,021,306	$ 948,234
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,142,966	1,036,515	1,001,843
Conservation and demand side management program amortization	5,225	6,033	6,531
Nuclear fuel amortization	106,424	114,542	98,089
Deferred income taxes	535,868	569,378	515,062
Amortization of investment tax credits	(5,277)	(5,543)	(5,753)
Allowance for equity funds used during construction	(55,936)	(89,750)	(87,683)
Equity earnings of unconsolidated subsidiaries	(34,390)	(30,151)	(30,020)
Dividends from unconsolidated subsidiaries	40,128	36,707	36,416
Provision for bad debts	36,074	42,765	37,627
Share-based compensation expense	44,928	32,189	24,613
Gain on sale of transmission assets	—	—	(13,661)
Loss on Monticello life cycle management/extended power uprate project	129,463	—	—
Net realized and unrealized hedging and derivative transactions	21,919	5,506	(4,704)
Other, net	(1,326)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	65,826	(125,146)	(108,911)
Accrued unbilled revenues	73,625	(41,262)	(23,867)
Inventories	(11,240)	(20,558)	(43,588)
Other current assets	9,273	(111,300)	(18,071)
Accounts payable	(120,002)	(53,242)	132,441
Net regulatory assets and liabilities	102,465	195,823	141,325
Other current liabilities	66,134	137,147	126,555
Pension and other employee benefit obligations	(69,256)	(101,457)	(156,369)
Change in other noncurrent assets	10,553	44,364	(9,998)
Change in other noncurrent liabilities	(52,090)	(15,674)	17,925
Net cash provided by operating activities	3,025,839	2,648,192	2,584,036
Investing activities			
Utility capital/construction expenditures	(3,683,359)	(3,199,791)	(3,395,325)
Allowance for equity funds used during construction	55,936	89,750	87,683
Proceeds from sale of transmission assets	—	—	37,118
Proceeds from insurance recoveries	27,237	6,000	90,000
Purchases of investments in external decommissioning fund	(1,257,924)	(595,569)	(1,481,881)
Proceeds from the sale of investments in external decommissioning fund	1,236,873	588,430	1,461,291
Investments in WYCO Development LLC and other	(1,392)	(2,376)	(7,504)
Other, net	(145)	(3,695)	(4,766)
Net cash used in investing activities	(3,622,774)	(3,117,251)	(3,213,384)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(173,500)	260,500	157,000
Proceeds from issuance of long-term debt	1,626,212	837,584	1,431,895
Repayments of long-term debt	(250,882)	(275,948)	(652,451)
Proceeds from issuance of common stock	7,011	180,798	231,767
Dividends paid	(606,574)	(561,411)	(514,042)
Net cash provided by financing activities	602,267	441,523	654,169
Net change in cash and cash equivalents	5,332	(27,536)	24,821
Cash and cash equivalents at beginning of period	79,608	107,144	82,323
Cash and cash equivalents at end of period	$ 84,940	$ 79,608	$ 107,144
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (542,860)	$ (512,602)	$ (514,911)
Cash received (paid) for income taxes, net	58,287	(4,542)	17,188
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	$ 321,969	$ 417,473	$ 452,453
Issuance of common stock for reinvested dividends and 401(k) plans	52,911	62,078	56,950

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
Assets		
Current assets		
Cash and cash equivalents	$ 84,940	$ 79,608
Accounts receivable, net	724,606	826,506
Accrued unbilled revenues	654,867	728,492
Inventories	608,584	597,183
Regulatory assets	344,630	444,058
Derivative instruments	33,842	85,723
Deferred income taxes	140,219	246,210
Prepaid taxes	163,023	185,488
Prepayments and other	155,734	171,112
Total current assets	2,910,445	3,364,380
Property, plant and equipment, net	31,205,851	28,756,916
Other assets		
Nuclear decommissioning fund and other investments	1,902,995	1,832,640
Regulatory assets	2,858,741	2,774,216
Derivative instruments	51,083	53,775
Other	124,420	175,957
Total other assets	4,937,239	4,836,588
Total assets	$ 39,053,535	$ 36,957,884
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 657,021	$ 257,726
Short-term debt	846,000	1,019,500
Accounts payable	960,982	1,173,006
Regulatory liabilities	306,830	410,729
Taxes accrued	438,189	396,615
Accrued interest	166,829	158,536
Dividends payable	162,410	151,720
Derivative instruments	29,839	21,632
Other	490,197	475,119
Total current liabilities	4,058,297	4,064,583
Deferred credits and other liabilities		
Deferred income taxes	6,293,661	5,852,988
Deferred investment tax credits	68,419	73,696
Regulatory liabilities	1,332,889	1,163,429
Asset retirement obligations	2,608,562	2,446,631
Derivative instruments	168,311	183,936
Customer advances	228,999	256,945
Pension and employee benefit obligations	941,002	936,907
Other	261,756	264,653
Total deferred credits and other liabilities	11,903,599	11,179,185
Commitments and contingencies		
Capitalization		
Long-term debt	12,490,719	11,499,634
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,535,523 and 505,733,267 shares outstanding at Dec. 31, 2015 and 2014, respectively	1,268,839	1,264,333
Additional paid in capital	5,889,106	5,837,330
Retained earnings	3,552,728	3,220,958
Accumulated other comprehensive loss	(109,753)	(108,139)
Total common stockholders' equity	10,600,920	10,214,482
Total liabilities and equity	$ 39,053,535	$ 36,957,884

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2012	487,960	$ 1,219,899	$ 5,353,015	$ 2,413,816	$ (112,653)	$ 8,874,077
Net income				948,234		948,234
Other comprehensive income					6,378	6,378
Dividends declared on common stock				(554,067)		(554,067)
Issuances of common stock	10,012	25,030	237,671			262,701
Share-based compensation			28,627			28,627
Balance at Dec. 31, 2013	497,972	$ 1,244,929	$ 5,619,313	$ 2,807,983	$ (106,275)	$ 9,565,950
Net income				1,021,306		1,021,306
Other comprehensive loss					(1,864)	(1,864)
Dividends declared on common stock				(608,331)		(608,331)
Issuances of common stock	7,761	19,404	185,145			204,549
Share-based compensation			32,872			32,872
Balance at Dec. 31, 2014	505,733	$ 1,264,333	$ 5,837,330	$ 3,220,958	$ (108,139)	$ 10,214,482
Net income				984,485		984,485
Other comprehensive loss					(1,614)	(1,614)
Dividends declared on common stock				(652,715)		(652,715)
Issuances of common stock	1,803	4,506	28,017			32,523
Share-based compensation			23,759			23,759
Balance at Dec. 31, 2015	507,536	$ 1,268,839	$ 5,889,106	$ 3,552,728	$ (109,753)	$ 10,600,920

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	**2014**
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	$ —	$ 250,000
March 1, 2018, 5.25%	500,000	500,000
Aug. 15, 2020, 2.2%	300,000	—
Aug. 15, 2022, 2.15%	300,000	300,000
May 15, 2023, 2.6%	400,000	400,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	300,000
Aug. 15, 2040, 4.85%	250,000	250,000
Aug. 15, 2042, 3.4%	500,000	500,000
May 15, 2044, 4.125%	300,000	300,000
Aug. 15, 2045, 4.0%	300,000	—
Other	33	47
Unamortized discount	(15,911)	(11,365)
Total	4,534,122	4,188,682
Less current maturities	11	250,013
Total NSP-Minnesota long-term debt	$ 4,534,111	$ 3,938,669
PSCo		
First Mortgage Bonds, Series due:		
Sept. 1, 2017, 4.375% [a]	$ 129,500	$ 129,500
Aug. 1, 2018, 5.8%	300,000	300,000
June 1, 2019, 5.125%	400,000	400,000
Nov. 15, 2020, 3.2%	400,000	400,000
Sept. 15, 2022, 2.25%	300,000	300,000
March 15, 2023, 2.5%	250,000	250,000
May 15, 2025, 2.9%	250,000	—
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000
Sept. 15, 2042, 3.6%	500,000	500,000
March 15, 2043, 3.95%	250,000	250,000
March 15, 2044, 4.30%	300,000	300,000
Capital lease obligations, through 2060, 11.2% — 14.3%	164,031	172,209
Unamortized discount	(11,340)	(11,480)
Total	4,132,191	3,890,229
Less current maturities	8,103	8,178
Total PSCo long-term debt	$ 4,124,088	$ 3,882,051
SPS		
First Mortgage Bonds, Series due:		
June 15, 2024, 3.3%	$ 350,000	$ 150,000
Aug. 15, 2041, 4.5%	400,000	400,000
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Unamortized premium (discount)	605	(309)
Total	1,550,605	1,349,691
Less current maturities	200,000	—
Total SPS long-term debt	$ 1,350,605	$ 1,349,691

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION — (Continued)
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	$ 150,000	$ 150,000
June 15, 2024, 3.3%	200,000	100,000
Sept. 1, 2038, 6.375%	200,000	200,000
Oct. 1, 2042, 3.7%	100,000	100,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% [b]	18,600	18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%	490	523
Other	1,634	1,687
Unamortized discount	(3,131)	(2,519)
Total	667,593	568,291
Less current maturities	1,131	1,235
Total NSP-Wisconsin long-term debt	$ 666,462	$ 567,056
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2016-2052, 0% — 8%	$ 31,255	$ 32,037
Total	31,255	32,037
Less current maturities	709	1,316
Total other subsidiaries long-term debt	$ 30,546	$ 30,721
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
May 9, 2016, 0.75%	$ 450,000	$ 450,000
April 1, 2017, 5.613%	253,979	253,979
June 1, 2017, 1.2%	250,000	—
May 15, 2020, 4.7%	550,000	550,000
June 1, 2025, 3.3%	250,000	—
July 1, 2036, 6.5%	300,000	300,000
Sept. 15, 2041, 4.8%	250,000	250,000
Elimination of PSCo capital lease obligation with affiliates	(66,454)	(69,470)
Unamortized discount	(5,551)	(6,078)
Total	2,231,974	1,728,431
Less current maturities (including elimination of PSCo capital lease obligation)	447,067	(3,015)
Total Xcel Energy Inc. long-term debt	$ 1,784,907	$ 1,731,446
Total long-term debt	$ 12,490,719	$ 11,499,634
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,535,523 and 505,733,267 shares outstanding at Dec. 31, 2015 and Dec. 31, 2014, respectively	$ 1,268,839	$ 1,264,333
Additional paid in capital	5,889,106	5,837,330
Retained earnings	3,552,728	3,220,958
Accumulated other comprehensive loss	(109,753)	(108,139)
Total common stockholders' equity	$ 10,600,920	$ 10,214,482

(a) Pollution control financing.
(b) Resource recovery financing.

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. Xcel Energy's consolidated financial statements and disclosures are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — In 2015, Xcel Energy's operations included the activity of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in Xcel Energy's operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipelines, storage and compression facilities.

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

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and variable interest entities for which it is the primary beneficiary. In the consolidation process, all intercompany transactions and balances are eliminated. Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries. Xcel Energy has investments in several plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 5 for further discussion of jointly owned generation, transmission, and gas facilities and related ownership percentages.

Xcel Energy evaluates its arrangements and contracts with other entities, including but not limited to, investments, PPAs and fuel contracts to determine if the other party is a variable interest entity, if Xcel Energy has a variable interest and if Xcel Energy is the primary beneficiary. Xcel Energy follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether Xcel Energy is a variable interest entity's primary beneficiary. See Note 13 for further discussion of variable interest entities.

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 or potential disallowances, AROs, certain regulatory assets and liabilities, 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.

Regulatory Accounting — Our regulated utility subsidiaries account for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

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 treatment in the rate setting process.

If restructuring or other changes in the regulatory environment occur, regulated utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's financial condition, results of operations and cash flows. See Note 15 for further discussion of regulatory assets and liabilities.

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 recognized. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. Xcel Energy's utility subsidiaries recognize sales to both native load and other end use customers on a gross basis. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

Xcel Energy Inc.'s utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify for alternative revenue recognition under generally accepted accounting principles. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety, or other mandate. When certain criteria are met, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas systems. These programs include efficiency and redesign programs, as well as rebates for the purchase of items such as high efficiency lighting.

The costs incurred for DSM and CIP programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

For PSCo, SPS and NSP-Minnesota, DSM and CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage Xcel Energy's achievement of energy conservation goals and compensate for related lost sales margin. For these utility subsidiaries, regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers. NSP-Wisconsin recovers approved conservation program costs in base rate revenue.

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 AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate. Property, plant and equipment that is required to be decommissioned early by a regulator is reclassified as plant to be retired.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 12 for a discussion of the loss recognized related to the Monticello LCM/EPU project. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.8, 2.7, and 2.9 percent for the years ended Dec. 31, 2015, 2014 and 2013, respectively.

Leases — Xcel Energy evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 13 for further discussion of leases.

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

Generally, AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases commissions have approved a more current recovery of the cost of capital associated with large capital projects, resulting in a lower recognition of AFUDC. In other cases, some commissions have allowed an AFUDC calculation greater than the FERC-defined AFUDC rate, resulting in higher recognition of AFUDC.

AROs — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 13 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota's most recent triennial nuclear decommissioning studies were approved by the MPUC in October 2015. These studies reflect NSP-Minnesota's plans for prompt dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a U.S. government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. See Note 14 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the consolidated balance sheets. See Note 11 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling O&M costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

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

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

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize only applies to federal ITCs. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax.

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

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 6 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects or O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 11.

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction, or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective, are included in OCI or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

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

See Note 11 for further discussion of Xcel Energy's risk management and derivative activities.

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 electric operating revenues in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, and PSCo. 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 and commodity trading results include the impact of all margin-sharing mechanisms. See Note 11 for further discussion.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. See Note 11 for further discussion.

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

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

Inventory — All inventory is recorded at average cost.

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

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. As a result of state regulatory orders, Xcel Energy reduces recoverable fuel costs for the cost of certain RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Emission Allowances — Emission allowances, including the annual SO_2 and NOx emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. Xcel Energy follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenue and the operating activities section of the consolidated statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are 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.

Estimated remediation costs, excluding inflationary increases, are recorded 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 remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost. 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 before the related costs are incurred are classified as a regulatory liability.

See Note 13 for further discussion of environmental costs.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy Inc.'s utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 9 for further discussion of benefit plans and other postretirement benefits.

Guarantees — Xcel Energy recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as Xcel Energy is released from risk under the guarantee. See Note 13 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2015 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. The new guidance also includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers. As a result of the FASB's July 2015 deferral of the standard's required implementation date, the guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

Consolidation — In February 2015, the FASB issued *Amendments to the Consolidation Analysis, Topic 810 (ASU No. 2015-02)*, which reduces the number of consolidation models and amends certain consolidation principles related to variable interest entities. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Xcel Energy does not expect the implementation of ASU 2015-02 to have a material impact on its consolidated financial statements.

Presentation of Debt Issuance Costs — In April 2015, the FASB issued *Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30 (ASU No. 2015-03)*, which amends existing guidance to require the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of an asset. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the prescribed reclassification of assets to an offset of debt on the consolidated balance sheets, Xcel Energy does not expect the implementation of ASU 2015-03 to have a material impact on its consolidated financial statements.

Fair Value Measurement — In May 2015, the FASB issued *Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent), Topic 820 (ASU No. 2015-07),* which removes the requirement to categorize fair value measurements using a net asset value methodology in the fair value hierarchy. This guidance will be effective on a retrospective basis, effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the reduced disclosure requirements, Xcel Energy does not expect the implementation of ASU 2015-07 to have a material impact on its consolidated financial statements.

Presentation of Deferred Taxes — In November 2015, the FASB issued *Balance Sheet Classification of Deferred Taxes, Topic 740 (ASU No 2015-17),* which removes the requirement to present deferred tax assets and liabilities as current and noncurrent on the balance sheet based on the classification of the related asset or liability, and instead requires classification of all deferred tax assets and liabilities as noncurrent. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Other than the prescribed classification of all deferred tax assets and liabilities as noncurrent, Xcel Energy does not expect the implementation of ASU 2015-17 to have a material impact on its consolidated financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01),* which among other changes in accounting and disclosure requirements, replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes, and also eliminates the available-for-sale classification for marketable equity securities. Under the new guidance, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are to be recognized in earnings. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2016-01 on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	$ 776,494	$ 884,225
Less allowance for bad debts	(51,888)	(57,719)
	$ 724,606	$ 826,506

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	$ 290,690	$ 244,099
Fuel	202,271	183,249
Natural gas	115,623	169,835
	$ 608,584	$ 597,183

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	$ 36,464,050	$ 33,203,139
Natural gas plant	4,944,757	4,643,452
Common and other property	1,709,508	1,611,486
Plant to be retired [(a)]	38,249	71,534
CWIP	1,256,949	2,005,531
Total property, plant and equipment	44,413,513	41,535,142
Less accumulated depreciation	(13,591,259)	(13,168,418)
Nuclear fuel	2,447,251	2,347,422
Less accumulated amortization	(2,063,654)	(1,957,230)
	$ 31,205,851	$ 28,756,916

(a) PSCo's Cherokee Unit 3 was retired in August 2015. In 2017, PSCo expects to both early retire Valmont Unit 5 and convert Cherokee Unit 4 from a coal-fueled generating facility to natural gas, as approved by the CPUC. Amounts are presented net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	$ 2,750
Amount outstanding at period end	846
Average amount outstanding	290
Maximum amount outstanding	846
Weighted average interest rate, computed on a daily basis	0.56%
Weighted average interest rate at period end	0.82

	Year Ended Dec. 31		
(Amounts in Millions, Except Interest Rates)	2015	2014	2013
Borrowing limit	$ 2,750	$ 2,750	$ 2,450
Amount outstanding at period end	846	1,020	759
Average amount outstanding	601	841	481
Maximum amount outstanding	1,360	1,200	1,160
Weighted average interest rate, computed on a daily basis	0.48%	0.33%	0.31%
Weighted average interest rate at end of period	0.82	0.56	0.25

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2015 and 2014, there were $29 million and $61 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. 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.

Credit Agreements — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.75 billion and each credit facility matures in October 2019.

NSP-Minnesota, PSCo, SPS, and Xcel Energy Inc. each have the right to request an extension of the termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

Features of the credit facilities include:

- Xcel Energy Inc. may increase its credit facility by up to $200 million, NSP-Minnesota and PSCo may each increase their credit facilities by $100 million and SPS may increase its credit facility by $50 million. The NSP-Wisconsin credit facility cannot be increased.
- Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at Dec. 31, 2015 and 2014, respectively, as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
	2015	2014
Xcel Energy Inc.	57%	56%
NSP-Wisconsin	46	48
NSP-Minnesota	48	48
SPS	46	47
PSCo	45	47

- If Xcel Energy Inc. or any of its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.
- The Xcel Energy Inc. credit facility has a cross-default provision that provides Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries, except NSP-Wisconsin as long as its total assets do not comprise more than 15 percent of Xcel Energy's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding $75 million.
- Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants in their debt agreements as of Dec. 31, 2015 and 2014.
- The interest rates under these lines of credit are based on Eurodollar borrowing margins ranging from 87.5 to 175 basis points per year based on the applicable long-term credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 7.5 to 27.5 basis points per year.

At Dec. 31, 2015, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,000	$ 584	$ 416
PSCo	700	18	682
NSP-Minnesota	500	241	259
SPS	400	22	378
NSP-Wisconsin	150	10	140
Total	$ 2,750	$ 875	$ 1,875

(a) These credit facilities mature in October 2019.
(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Dec. 31, 2015 and 2014.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Maturities of long-term debt are as follows:

(Millions of Dollars)		
2016	$	657
2017		638
2018		1,206
2019		406
2020		1,257

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025;
- NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- SPS issued $200 million of 3.3 percent first mortgage bonds due June 15, 2024.

During 2014, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued $300 million of 4.3 percent first mortgage bonds due March 15, 2044;
- NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- SPS issued $150 million of 3.3 percent first mortgage bonds due June 15, 2024; and
- NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024.

In 2014, in connection with SPS' issuance of $150 million of 3.30 percent first mortgage bonds due June 15, 2024, SPS concurrently secured its previously issued Series G Senior Notes due Dec. 1, 2018 equally and ratably with SPS' first mortgage bonds as required pursuant to the terms of the Series G notes.

Also in 2014, to provide the required collateralization, SPS issued $250 million of collateral 8.75 percent first mortgage bonds due Dec. 1, 2018 to the trustee under its senior unsecured indenture which secured the previously issued Series G Senior Notes, 8.75 percent due Dec. 1, 2018, equally and ratably with SPS' first mortgage bonds.

Issuances of Common Stock — During the year ended Dec. 31, 2014, Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an at-the-market (ATM) program and received cash proceeds of $172.7 million net of $1.9 million in fees and commissions. Xcel Energy completed its ATM program as of June 30, 2014. The proceeds from the issuances of common stock were used to repay short-term debt, infuse equity into the utility subsidiaries and for other general corporate purposes.

Deferred Financing Costs — Other assets included deferred financing costs of approximately $92 million and $85 million, net of amortization, at Dec. 31, 2015 and 2014, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — Xcel Energy Inc. has 7,000,000 shares of preferred stock authorized to be issued with a $100 par value. At Dec. 31, 2015 and 2014, there were no shares of preferred stock outstanding.

The charters of PSCo and SPS authorize each subsidiary to issue 10,000,000 shares of preferred stock with par values of $0.01 and $1.00 per share, respectively. At Dec. 31, 2015 and 2014, there were no preferred shares of subsidiaries outstanding.

Xcel Energy Inc. has 1,000,000,000 shares of common stock authorized to be issued with a $2.50 par value. Outstanding shares at Dec. 31, 2015 and 2014 were 507,535,523 and 505,733,267, respectively.

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its subsidiaries to pay dividends. All of Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only. Due to certain restrictive covenants, Xcel Energy Inc. is required to be current on particular interest payments before dividends can be paid.

The most restrictive dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS are imposed by their respective state regulatory commission. PSCo's dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

Only NSP-Minnesota has a first mortgage indenture which places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than $1.7 billion and $1.6 billion in additional cash dividends to Xcel Energy Inc. at Dec. 31, 2015 and 2014, respectively.

NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2015 and $967 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was $9.9 billion at Dec. 31, 2015, which did not exceed the limit of $10.5 billion.

NSP-Wisconsin cannot pay annual dividends in excess of approximately $33.3 million if its calendar year average equity-to-total capitalization ratio is or falls below the state commission authorized level of 52.5 percent, as calculated consistent with PSCW requirements. NSP-Wisconsin's calendar year average equity-to-total capitalization ratio calculated on this basis was 52.6 percent at Dec. 31, 2015 and $2.4 million in retained earnings was not restricted.

SPS' state regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc. by requiring an equity-to-total capitalization ratio (excluding short-term debt) between 45.0 percent and 55.0 percent. In addition, SPS may not pay a dividend that would cause it to lose its investment grade bond rating. SPS' equity-to-total capitalization ratio (excluding short-term debt) was 53.8 percent at Dec. 31, 2015 and $438 million in retained earnings was not restricted.

The issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC. As of Dec. 31, 2015:

- PSCo has authorization to issue up to an additional $450 million of long-term debt and up to $800 million of short-term debt.
- SPS has authorization to issue up to $100 million of long-term debt and $500 million of short-term debt.
- NSP-Wisconsin has authorization to issue up to $150 million of short-term debt and NSPW will file for additional long-term debt authorization.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 46.9 percent and 57.3 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $10.5 billion.

Xcel Energy believes these authorizations are adequate and seeks additional authorization as necessary.

5. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by Xcel Energy Inc.'s utility subsidiaries in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2015:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	$ 590,048	$ 386,675	$ 4,984	59%
Sherco Common Facilities Units 1, 2 and 3	145,825	93,583	47	80
Sherco Substation	4,790	3,054	—	59
Electric Transmission:				
Grand Meadow Line and Substation	9,248	1,451	—	50
CapX2020 Transmission	947,674	107,985	68,834	51
Total NSP-Minnesota	$ 1,697,585	$ 592,748	$ 73,865	

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Wisconsin				
Electric Transmission:				
CapX2020 Transmission	$ 154,394	$ 6,863	$ 1,633	80%
La Crosse, Wis. to Madison, Wis.	—	—	18,894	37
Total NSP-Wisconsin	$ 154,394	$ 6,863	$ 20,527	

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
PSCo				
Electric Generation:				
Hayden Unit 1	$ 155,159	$ 69,679	$ 147	76%
Hayden Unit 2	121,486	61,780	20,840	37
Hayden Common Facilities	37,756	17,910	321	53
Craig Units 1 and 2	60,158	36,570	8,518	10
Craig Common Facilities 1, 2 and 3	37,418	18,520	505	7
Comanche Unit 3	892,340	95,029	452	67
Comanche Common Facilities	23,826	1,430	894	82
Electric Transmission:				
Transmission and other facilities, including substations	152,460	62,324	5,378	Various
Gas Transportation:				
Rifle, Colo. to Avon, Colo.	19,928	7,165	—	60
Gas Transportation Compressor	8,353	124	127	50
Total PSCo	$ 1,508,884	$ 370,531	$ 37,182	

NSP-Minnesota and PSCo have approximately 517 MW and 820 MW of jointly owned generating capacity, respectively. Each Company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

Consolidated Appropriations Act, 2016 - In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

- Immediate expensing, or "bonus depreciation," of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. Additionally, some longer production period property placed in service in 2020 will be eligible for bonus depreciation;
- PTCs at 100 percent of the credit rate ($0.023 per KWh) for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;
- ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- R&E credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment. The fourth quarter 2015 accounting impacts included:

- Recognition of additional tax deductions for bonus depreciation of $1.2 billion, and as a result, recognition of $4.9 million benefit related to a carryback claim (see additional discussion below) and $3.5 million expense related to valuation allowances and expirations of charitable contribution carryforwards; and
- Recognition of $6.8 million benefit for federal R&E credits.

Tax Increase Prevention Act of 2014 — In 2014, the Tax Increase Prevention Act (TIPA) was signed into law. The TIPA provides for the following:

- The R&E credit was extended for 2014;
- PTCs were extended for projects that began construction before the end of 2014 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2014. Additionally, some longer production period property placed in service in 2015 is also eligible for 50 percent bonus depreciation.

The accounting related to the TIPA was recorded beginning in the fourth quarter of 2014 because a change in tax law is accounted for in the period of enactment.

American Taxpayer Relief Act of 2012 — In 2013, the American Taxpayer Relief Act (ATRA) was signed into law. The ATRA provided for the following:

- The top tax rate for dividends increased from 15 percent to 20 percent. The 20 percent dividend rate is now consistent with the tax rates for capital gains;
- The R&E credit was extended for 2012 and 2013;
- PTCs were extended for projects that began construction before the end of 2013 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2013. Additionally, some longer production period property placed in service in 2014 is also eligible for 50 percent bonus depreciation.

The accounting related to the ATRA, including the provisions related to 2012, was recorded beginning in the first quarter of 2013 because a change in tax law is accounted for in the period of enactment.

Federal Tax Loss Carryback Claims — In 2012, 2013, 2014 and 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014 and $12 million in 2013 and $15 million in 2012.

Federal Audit **—** Xcel Energy files a consolidated federal income tax return. In the third quarter of 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $14 million of income tax expense for the 2009 through 2011 and 2013 claims, the recently filed 2014 claim, and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals); however the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009 through 2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the Appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Dec. 31, 2015, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

State Audits **—** Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Dec. 31, 2015, Xcel Energy’s earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2011

As of Dec. 31, 2015, there were no state income tax audits in progress.

Unrecognized Tax Benefits **—** The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	$ 25.8	$ 16.2
Unrecognized tax benefit — Temporary tax positions	94.9	50.3
Total unrecognized tax benefit	$ 120.7	$ 66.5

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2015	2014	2013
Balance at Jan. 1	$ 66.5	$ 41.2	$ 34.5
Additions based on tax positions related to the current year	27.1	28.7	15.1
Reductions based on tax positions related to the current year	(4.5)	(2.0)	(0.4)
Additions for tax positions of prior years	34.8	16.0	21.6
Reductions for tax positions of prior years	(2.9)	(6.0)	(4.8)
Settlements with taxing authorities	(0.3)	(9.6)	(24.8)
Lapse of applicable statutes of limitations	—	(1.8)	—
Balance at Dec. 31	$ 120.7	$ 66.5	$ 41.2

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	$ (36.7)	$ (28.5)

It is reasonably possible that Xcel Energy’s amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals and audit progress and state audits resume. As the IRS Appeals and audit progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $58 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Dec. 31, 2015, 2014 and 2013 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2015, 2014 or 2013.

Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2015	2014
Federal NOL carryforward	$ 2,153	$ 1,349
Federal tax credit carryforwards	360	327
State NOL carryforwards	2,124	1,722
Valuation allowances for state NOL carryforwards	(65)	(53)
State tax credit carryforwards, net of federal detriment [(a)]	45	19
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(24)	—

(a) State tax credit carryforwards are net of federal detriment of $24 million and $10 million as of Dec. 31, 2015 and 2014, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $13 million as of Dec. 31, 2015.

The federal carryforward periods expire between 2021 and 2035. The state carryforward periods expire between 2016 and 2035.

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

	2015	2014	2013
Federal statutory rate	35.0 %	35.0 %	35.0 %
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.1	4.0	4.1
Change in unrecognized tax benefits	0.6	0.2	0.6
NOL carryback	(0.3)	(0.9)	(0.8)
Regulatory differences — utility plant items	(1.0)	(1.3)	(1.6)
Tax credits recognized, net of federal income tax expense	(2.7)	(2.6)	(2.6)
Other, net	(0.2)	(0.5)	(0.9)
Effective income tax rate	35.5 %	33.9 %	33.8 %

The components of Xcel Energy’s income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Current federal tax (benefit)	$ (36,129)	$ (73,160)	$ (46,173)
Current state tax expense	2,324	9,225	7,678
Current change in unrecognized tax expense	45,933	23,915	13,162
Deferred federal tax expense	480,078	505,236	439,085
Deferred state tax expense	92,132	84,787	80,907
Deferred change in unrecognized tax (benefit)	(36,342)	(20,645)	(4,930)
Deferred investment tax credits	(5,277)	(5,543)	(5,753)
Total income tax expense	$ 542,719	$ 523,815	$ 483,976

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Deferred tax expense excluding items below	$ 546,664	$ 616,934	$ 588,053
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(11,810)	(48,674)	(64,420)
Tax benefit (expense) allocated to OCI	1,013	1,117	(8,572)
Other	1	1	1
Deferred tax expense	$ 535,868	$ 569,378	$ 515,062

The components of Xcel Energy's net deferred tax liability (current and noncurrent) at Dec. 31 were as follows:

(Thousands of Dollars)	2015	2014
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 7,119,023	$ 6,257,191
Regulatory assets	313,414	300,762
Other	243,690	300,251
Total deferred tax liabilities	$ 7,676,127	$ 6,858,204
Deferred tax assets:		
NOL carryforward	$ 851,242	$ 552,274
Tax credit carryforward	404,738	346,064
Unbilled revenue - fuel costs	57,220	55,021
Rate refund	50,441	93,956
Regulatory liabilities	41,541	49,712
Environmental remediation	38,663	42,716
Deferred investment tax credits	29,650	31,886
NOL and tax credit valuation allowances	(27,679)	(3,402)
Other	76,869	83,199
Total deferred tax assets	$ 1,522,685	$ 1,251,426
Net deferred tax liability	$ 6,153,442	$ 5,606,778

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements.

Common stock equivalents causing a dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants. In October 2013, Xcel Energy determined that it would settle 401(k) employer matching contributions in cash instead of common stock going forward for most of its employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements. Following the effective date of a new PSCo bargaining agreement in August 2015, 401(k) matching contributions will be settled in cash for all Xcel Energy employee groups.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows:

	2015			2014			2013		
(Amounts in thousands, except per share data)	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**
Net income	$ 984,485			$ 1,021,306			$ 948,234		
Basic EPS:									
Earnings available to common shareholders	984,485	507,768	$ 1.94	1,021,306	503,847	$ 2.03	948,234	496,073	$ 1.91
Effect of dilutive securities:									
Equity awards	—	400		—	270		—	459	
Diluted EPS:									
Earnings available to common shareholders	$ 984,485	508,168	$ 1.94	$ 1,021,306	504,117	$ 2.03	$ 948,234	496,532	$ 1.91

Dividend Reinvestment and Stock Purchase Plan and Stock Compensation Settlements — In October 2015, the Xcel Energy Inc. Board of Directors authorized open market purchases by the plan administrator as the source of shares for the dividend reinvestment program as well as market purchases of up to 3.0 million shares for stock compensation plan settlements.

8. Share-Based Compensation

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Xcel Energy Inc. reinvests dividends on the restricted stock while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Xcel Energy Inc. granted shares of restricted stock for the years ended Dec. 31 as follows:

(Shares in Thousands)	**2015**	**2014**	**2013**
Granted shares	42	46	33
Grant date fair value	$ 35.00	$ 29.69	$ 28.30

A summary of the changes of nonvested restricted stock for the year ended 2015 were as follows:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2015	82	$ 29.00
Granted	42	35.00
Forfeited	(9)	28.24
Vested	(35)	28.30
Dividend equivalents	3	35.19
Nonvested restricted stock at Dec. 31, 2015	83	32.62

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated in 2010) and the 2015 Omnibus Incentive Plan (effective May 20, 2015). These plans allow the attachment of various vesting conditions and performance goals to the awards granted. The vesting conditions and performance goals may vary by plan year. At the end of the restricted period, such grants will be awarded if the vesting conditions and/or performance goals are met.

Commencing in 2014, certain employees were granted bundled equity awards with one portion of shares subject only to service conditions, and the other portion subject to performance conditions. Inclusive of other grants of time-based awards, a total of 0.3 million, 0.4 million, and 0.2 million time-based equity shares subject only to service conditions were granted in 2015, 2014, and 2013, respectively. Other than shares associated with these time-based awards, restricted stock and certain 401(k) employer match settlements, payout of all other employee equity awards and the lapsing of restrictions on the transfer of units are based on the achievement of performance criteria.

The performance conditions for a portion of the awards granted in 2015 and 2014 are based on relative TSR, measured identically to TSR liability awards granted in those years, and measurement of performance for a portion of units awarded from 2011 to 2013 is based on EPS growth with an additional condition that Xcel Energy Inc.'s annual dividend paid on its common stock remains at a specified amount per share or greater. The performance conditions for the remaining employee equity awards are based on environmental goals. Equity awards with performance conditions awarded from 2011 to 2015, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years, with potential payouts ranging from zero to 150 percent for 2011 to 2013 grants, and zero to 200 percent for 2014 and 2015 grants, depending on the level of achievement.

- The 2010 environmental awards met their targets as of Dec. 31, 2012 and were settled in shares in February 2013.
- The 2011 awards measured on EPS growth and the 2011 environmental awards met their targets as of Dec. 31, 2013 and were settled in shares in February 2014.
- The 2012 awards measured on EPS growth and the 2012 environmental awards met their targets as of Dec. 31, 2014, and were settled in shares in February 2015.
- The 2013 awards measured on EPS growth, the 2013 environmental awards and the 2013 time-based awards met their targets as of Dec. 31, 2015, and will be settled in shares in February 2016.

Equity award units granted to employees, excluding restricted stock and applicable 401(k) employer match settlements, for the years ended Dec. 31 were as follows:

(Units in Thousands)	2015	2014	2013
Granted units	496	588	774
Weighted average grant date fair value	$ 36.09	$ 29.90	$ 27.65

Approximately 0.8 million of these units vested during 2015 at a total fair value of $27.1 million. Approximately 0.5 million of these units vested during 2014 at a total fair value of $19.6 million. Approximately 0.6 million of these units vested during 2013 at a total fair value of $16.8 million.

A summary of the changes in the nonvested portion of these equity award units for the year ended 2015, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2015	1,322	$ 28.63
Granted	496	36.09
Forfeited	(99)	30.97
Vested	(756)	27.67
Dividend equivalents	62	30.25
Nonvested Units at Dec. 31, 2015	1,025	32.81

The total fair value of these nonvested equity awards as of Dec. 31, 2015 was $36.8 million and the weighted average remaining contractual life was 1.7 years.

Stock Equivalent Units **—** Non-employee members of the Xcel Energy Inc. Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy Inc. common stock. The annual grants are vested as of the date of each member's election to the Board of Directors; there is no further service or other condition attached to the annual grants. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash. Dividends on Xcel Energy Inc.'s common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy Inc.'s common stock upon a director's termination of service.

The stock equivalent units granted for the years ended Dec. 31 were as follows:

(Units in Thousands)	2015	2014	2013
Granted units	60	62	69
Grant date fair value	$ 34.58	$ 30.57	$ 29.52

A summary of the stock equivalent unit changes for the year ended 2015 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2015	690	$ 24.03
Granted	60	34.58
Units distributed	(29)	20.71
Dividend equivalents	25	35.26
Stock equivalent units at Dec. 31, 2015	746	25.38

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective in 2010). The plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards granted have been historically dependent on a single measure of performance, Xcel Energy Inc.'s relative TSR measured over a three-year period. For 2015, 2014 and 2013 awards, Xcel Energy Inc.'s TSR is compared to the TSR of other companies in a 23-member utilities peer group. At the end of the three-year period, potential payouts of the awards range from zero to 200 percent, depending on Xcel Energy Inc.'s TSR compared to the applicable peer group or index.

The TSR liability awards granted for the years ended Dec. 31 were as follows:

(In Thousands)	2015	2014	2013
Awards granted	224	270	215

The total amounts of TSR liability awards settled during the years ended Dec. 31 were as follows:

(In Thousands)	2015	2014	2013
Awards settled	—	—	108
Settlement amount (cash and common stock)	$ —	$ —	$ 3,057

The amount of cash used to settle Xcel Energy's TSR liability awards was $1.5 million in 2013.

Share-Based Compensation Expense — Other than for restricted stock and certain 401(k) employer match settlements, the vesting of employee equity awards is generally predicated on the achievement of a performance condition, which is the achievement of a TSR, EPS or environmental measures target. Additionally, approximately 0.3 million, 0.4 million, and 0.2 million of equity awards were granted in 2015, 2014, and 2013, respectively, with vesting subject only to service conditions for periods up to five years. Generally, all of these instruments are considered to be equity awards since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. The grant date fair value of equity awards is expensed over the service period as employees vest in their rights to those awards.

The TSR liability awards have been historically settled partially in cash, and therefore do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2015	2014	2013
Compensation cost for share-based awards [(a)] [(b)]	$ 44,928	$ 32,189	$ 24,613
Tax benefit recognized in income	17,570	12,557	9,571
Capitalized compensation cost for share-based awards [(c)]	—	1,887	1,698

(a) Compensation costs for share-based payment arrangements are included in O&M expense in the consolidated statements of income.

(b) Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totaled $7.4 million, and $7.0 million for the years ended 2014 and 2013, respectively. In October 2013, Xcel Energy determined that it would settle the 401(k) employer match in cash instead of common stock going forward for all employee groups except PSCo bargaining employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements. In August 2015, consistent with a new PSCo bargaining agreement, share-based compensation accounting ceased for the employer 401(k) match for PSCo bargaining employees, which will be paid in cash. As a result, 2015 compensation cost for share-based awards includes no 401(k) matching contributions.

(c) An allocated amount of the 401(k) match is capitalized.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2015 Omnibus Incentive Plan (effective May 20, 2015) is 7.0 million shares. The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) is 8.3 million shares. Under the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010), the total number of shares approved for issuance is 1.2 million shares.

As of Dec. 31, 2015 and 2014, there was approximately $36.4 million and $27.8 million, respectively, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the amount unrecognized at Dec. 31, 2015 over a weighted average period of 1.7 years.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 47 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2015:

- NSP-Minnesota had 1,983 and NSP-Wisconsin had 400 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 265 nuclear operation bargaining employees covered under several collective-bargaining agreements. Some of these agreements expired in 2015, but were extended to 2016. The remaining agreements expire in 2016 and 2018.
- PSCo had 2,024 bargaining employees covered under a collective-bargaining agreement, which expires in May 2017.
- SPS had 842 bargaining employees covered under a collective-bargaining agreement, which expired in October 2014. While collective bargaining is ongoing, the terms and conditions of the expired agreement are automatically extended until the parties reach an agreement or a decision is rendered by an arbitrator.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. Preferred stock is valued using recent trades and quoted prices of similar securities. The fair values for commingled funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on the plan’s evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, 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.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2015 and 2014 were $41.8 million and $46.5 million, respectively. In 2015 and 2014, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $9.5 million and $4.7 million, respectively. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the 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. Xcel Energy continually reviews its pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2015 were below the assumed level of 7.09 percent;
- Investment returns in 2014 were above the assumed level of 7.05 percent;
- Investment returns in 2013 were below the assumed level of 6.88 percent; and
- In 2016, Xcel Energy's expected investment return assumption is 6.87 percent.

The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	39%	37%
Long-duration fixed income and interest rate swap securities	27	27
Short-to-intermediate fixed income securities	13	13
Alternative investments	19	21
Cash	2	2
Total	100%	100%

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

	Dec. 31, 2015			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 178,884	$ —	$ —	$ 178,884
Derivatives	—	2,850	—	2,850
Government securities	—	412,932	—	412,932
Corporate bonds	—	248,439	—	248,439
Asset-backed securities	—	2,446	—	2,446
Common stock	93,831	—	—	93,831
Private equity investments	—	—	126,396	126,396
Commingled funds	—	1,759,066	—	1,759,066
Real estate	—	—	55,935	55,935
Other	—	3,001	—	3,001
Total	$ 272,715	$ 2,428,734	$ 182,331	$ 2,883,780

	Dec. 31, 2014			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 193,141	$ —	$ —	$ 193,141
Derivatives	—	1,590	—	1,590
Government securities	—	439,186	—	439,186
Corporate bonds	—	318,161	—	318,161
Asset-backed securities	—	3,759	—	3,759
Mortgage-backed securities	—	11,047	—	11,047
Common stock	102,667	—	—	102,667
Private equity investments	—	—	151,871	151,871
Commingled funds	—	1,826,420	—	1,826,420
Real estate	—	—	54,657	54,657
Securities lending collateral obligation and other	—	(18,728)	—	(18,728)
Total	$ 295,808	$ 2,581,435	$ 206,528	$ 3,083,771

The following tables present the changes in Xcel Energy's Level 3 pension plan assets for the years ended Dec. 31, 2015, 2014 and 2013:

(Thousands of Dollars)	Jan. 1, 2015	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2015
Private equity investments	$ 151,871	$ 28,094	$ (40,848)	$ (12,721)	$ —	$ 126,396
Real estate	54,657	7,083	(8,443)	2,638	—	55,935
Total	$ 206,528	$ 35,177	$ (49,291)	$ (10,083)	$ —	$ 182,331

(Thousands of Dollars)	Jan. 1, 2014	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	$ 152,849	$ 25,694	$ (17,573)	$ (9,099)	$ —	$ 151,871
Real estate	47,553	3,569	(2,443)	5,978	—	54,657
Total	$ 200,402	$ 29,263	$ (20,016)	$ (3,121)	$ —	$ 206,528

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 [(a)]	Dec. 31, 2013
Asset-backed securities	$ 14,639	$ —	$ —	$ —	$ (14,639)	$ —
Mortgage-backed securities	39,904	—	—	—	(39,904)	—
Private equity investments	158,498	22,058	(24,335)	(3,372)	—	152,849
Real estate	64,597	(2,659)	8,690	9,317	(32,392)	47,553
Total	$ 277,638	$ 19,399	$ (15,645)	$ 5,945	$ (86,935)	$ 200,402

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations **—** A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2015	2014
Accumulated Benefit Obligation at Dec. 31	$ 3,368,239	$ 3,545,928
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 3,746,752	$ 3,440,704
Service cost	99,311	88,342
Interest cost	148,524	156,619
Actuarial (gain) loss	(169,678)	342,826
Benefit payments	(256,982)	(281,739)
Obligation at Dec. 31	$ 3,567,927	$ 3,746,752

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 3,083,771	$ 3,010,140
Actual (loss) return on plan assets	(33,102)	224,808
Employer contributions	90,093	130,562
Benefit payments	(256,982)	(281,739)
Fair value of plan assets at Dec. 31	$ 2,883,780	$ 3,083,771

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status [(a)]	$ (684,147)	$ (662,981)

(a) Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheets.

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 1,710,097	$ 1,757,935
Prior service credit	(9,073)	(10,878)
Total	$ 1,701,024	$ 1,747,057

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	$ 105,426	$ 113,432
Noncurrent regulatory assets	1,520,975	1,558,649
Deferred income taxes	29,002	29,143
Net-of-tax accumulated OCI	45,621	45,833
Total	$ 1,701,024	$ 1,747,057
Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.66%	4.11%
Expected average long-term increase in compensation level	4.00	3.75
Mortality table	RP 2014	RP 2014

Mortality — In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on its population and specific experience. During 2015, a new projection table was released (MP 2015). Xcel Energy evaluated the updated projection table and concluded that the methodology, adopted at Dec. 31, 2014, is consistent with the recently updated table and continues to be representative of its population.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2013 through 2016 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $125.0 million in January 2016;
- $90.1 million in 2015;
- $130.6 million in 2014; and
- $192.4 million in 2013.

For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments — In 2015 and 2014 there were no plan amendments made which affected the projected benefit obligation. The 2013 decrease of the projected benefit obligation for plan amendments is due to fully insuring the long-term disability benefit for NSP bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

Benefit Costs — The components of Xcel Energy's net periodic pension cost were:

(Thousands of Dollars)	2015	2014	2013
Service cost	$ 99,311	$ 88,342	$ 96,282
Interest cost	148,524	156,619	140,690
Expected return on plan assets	(213,890)	(207,205)	(198,452)
Amortization of prior service (credit) cost	(1,805)	(1,746)	5,871
Amortization of net loss	125,152	116,762	144,151
Net periodic pension cost	157,292	152,772	188,542
Costs not recognized due to effects of regulation	(29,633)	(26,315)	(36,724)
Net benefit cost recognized for financial reporting	$ 127,659	$ 126,457	$ 151,818

	2015	2014	2013
Significant Assumptions Used to Measure Costs:			
Discount rate	4.11%	4.75%	4.00%
Expected average long-term increase in compensation level	3.75	3.75	3.75
Expected average long-term rate of return on assets	7.09	7.05	6.88

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 2016 pension cost calculations is 6.87 percent.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately $34.1 million in 2015, $32.4 million in 2014 and $30.3 million in 2013.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota and NSP-Wisconsin discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for PSCo and SPS, nonbargaining employees retiring after June 30, 2003.
- Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

***Plan Assets* —** Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	25%	25%
Short-to-intermediate fixed income securities	57	57
Alternative investments	13	13
Cash	5	5
Total	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 asset portfolio. The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

	Dec. 31, 2015			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 19,638	$ —	$ —	$ 19,638
Government securities	—	39,241	—	39,241
Insurance contracts	—	47,205	—	47,205
Corporate bonds	—	72,876	—	72,876
Asset-backed securities	—	28,691	—	28,691
Mortgage-backed securities	—	35,612	—	35,612
Commingled funds	—	204,782	—	204,782
Other	—	(412)	—	(412)
Total	$ 19,638	$ 427,995	$ —	$ 447,633

(Thousands of Dollars)	Dec. 31, 2014 Level 1	Level 2	Level 3	Total
Cash equivalents [a]	$ 26,324	$ —	$ —	$ 26,324
Derivatives	—	186	—	186
Government securities	—	48,584	—	48,584
Insurance contracts	—	50,351	—	50,351
Corporate bonds	—	54,207	—	54,207
Asset-backed securities	—	3,619	—	3,619
Mortgage-backed securities	—	11,250	—	11,250
Commingled funds	—	282,378	—	282,378
Other	—	(1,841)	—	(1,841)
Total	$ 26,324	$ 448,734	$ —	$ 475,058

[a] Includes restricted cash of $1.0 million at Dec. 31, 2014.

For the years ended Dec. 31, 2015 and 2014 there were no assets transferred in or out of Level 3. The following table presents the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2013:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 [a]	Dec. 31, 2013
Private equity investments	$ 757	$ —	$ —	$ —	$ (757)	$ —
Real estate	39,958	—	—	—	(39,958)	—
Total	$ 40,715	$ —	$ —	$ —	$ (40,715)	$ —

[a] Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations **—** A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2015	2014
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 642,869	$ 731,428
Service cost	2,116	3,457
Interest cost	25,297	34,028
Medicare subsidy reimbursements	1,958	1,861
Plan participants' contributions	6,718	7,148
Actuarial gain	(45,793)	(81,699)
Benefit payments	(48,898)	(53,354)
Obligation at Dec. 31	$ 584,267	$ 642,869

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 475,058	$ 492,036
Actual (loss) return on plan assets	(3,570)	12,083
Plan participants' contributions	6,718	7,148
Employer contributions	18,325	17,145
Benefit payments	(48,898)	(53,354)
Fair value of plan assets at Dec. 31	$ 447,633	$ 475,058

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status	$ (136,634)	$ (167,811)
Noncurrent assets	1,820	1,014
Current liabilities	(7,495)	(9,110)
Noncurrent liabilities	(130,959)	(159,715)
Net postretirement amounts recognized on consolidated balance sheets	$ (136,634)	$ (167,811)

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 103,039	$ 124,064
Prior service credit	(64,925)	(75,610)
Total	$ 38,114	$ 48,454

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	$ 352	$ 285
Noncurrent regulatory assets	50,135	59,697
Current regulatory liabilities	(985)	(892)
Noncurrent regulatory liabilities	(16,916)	(17,216)
Deferred income taxes	2,148	2,559
Net-of-tax accumulated OCI	3,380	4,021
Total	$ 38,114	$ 48,454

Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.65%	4.08%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial	6.00%	6.50%

Effective Jan. 1, 2016, the initial medical trend rate was decreased from 6.5 percent to 6.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	One-Percentage Point	
(Thousands of Dollars)	Increase	Decrease
APBO	$ 56,383	$ (47,972)
Service and interest components	3,113	(2,594)

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. Xcel Energy contributed $18.3 million during 2015, $17.1 million during 2014, $17.6 million during 2013 and expects to contribute approximately $12.3 million during 2016.

Plan Amendments **—** In 2015 and 2014, there were no plan amendments made which affected the benefit obligation.

Benefit Costs **—** The components of Xcel Energy's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2015	2014	2013
Service cost	$ 2,116	$ 3,457	$ 4,079
Interest cost	25,297	34,028	32,141
Expected return on plan assets	(26,600)	(33,954)	(33,011)
Amortization of transition obligation	—	—	825
Amortization of prior service credit	(10,686)	(10,688)	(12,501)
Amortization of net loss	5,404	11,740	22,325
Net periodic postretirement benefit cost	$ (4,469)	$ 4,583	$ 13,858

	2015	2014	2013
Significant Assumptions Used to Measure Costs:			
Discount rate	4.08%	4.82%	4.10%
Expected average long-term rate of return on assets	5.80	7.17	7.11

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
2016	$ 260,240	$ 48,047	$ 2,355	$ 45,692
2017	255,206	47,460	2,493	44,967
2018	263,689	47,039	2,637	44,402
2019	268,975	46,522	2,761	43,761
2020	271,853	46,819	2,869	43,950
2021-2025	1,353,351	220,122	16,053	204,069

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2015, 2014 and 2013. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 900 in 2015 from approximately 1,000 in 2014. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota and NSP-Wisconsin in multiemployer plans for the years presented:

(Thousands of Dollars)	2015	2014	2013
Multiemployer pension contributions:			
NSP-Minnesota	$ 17,223	$ 20,254	$ 23,515
NSP-Wisconsin	944	156	130
Total	$ 18,167	$ 20,410	$ 23,645
Multiemployer other postretirement benefit contributions:			
NSP-Minnesota	$ 135	$ 273	$ 390
Total	$ 135	$ 273	$ 390

10. Other Income, Net

Other income, net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2015	2014	2013
Interest income	$ 5,737	$ 7,353	$ 8,343
Other nonoperating income	3,514	4,866	3,025
Insurance policy expense	(3,851)	(6,923)	(8,292)
Other nonoperating expense	—	—	(104)
Other income, net	$ 5,400	$ 5,296	$ 2,972

11. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy's evaluation of its redemption rights, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs, purchased from MISO, PJM, ERCOT, SPP and NYISO. Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $328.8 million and $312.1 million at Dec. 31, 2015 and 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $100.2 million and $74.1 million at Dec. 31, 2015 and 2014, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2015 and 2014:

	Dec. 31, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$ 27,484	$ 27,484	$ —	$ —	$ 27,484
Commingled funds	392,838	—	410,634	—	410,634
International equity funds	259,114	—	231,122	—	231,122
Private equity investments	105,965	—	—	157,528	157,528
Real estate	61,816	—	—	84,750	84,750
Debt securities:					
Government securities	24,444	—	21,356	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	65,276
International corporate bonds	13,726	—	12,801	—	12,801
Municipal bonds	49,255	—	51,589	—	51,589
Asset-backed securities	2,837	—	2,830	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	11,621
Equity securities:					
Common stock	473,615	647,159	—	—	647,159
Total	$ 1,495,599	$ 674,643	$ 807,229	$ 242,278	$ 1,724,150

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $130.0 million of equity investments in unconsolidated subsidiaries and $48.9 million of miscellaneous investments.

	Dec. 31, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$ 24,184	$ 24,184	$ —	$ —	$ 24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341
Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	$ 1,465,922	$ 589,042	$ 949,393	$ 165,486	$ 1,703,921

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $83.1 million of equity investments in unconsolidated subsidiaries and $45.6 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3	Dec. 31, 2015
Private equity investments	$ 101,237	$ 32,029	$ —	$ 24,262	$ —	$ 157,528
Real estate	64,249	27,568	(9,611)	2,544	—	84,750
Total	$ 165,486	$ 59,597	$ (9,611)	$ 26,806	$ —	$ 242,278

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	$ 62,696	$ 22,078	$ (286)	$ 16,749	$ —	$ 101,237
Real estate	57,368	8,088	(9,794)	8,587	—	64,249
Total	$ 120,064	$ 30,166	$ (10,080)	$ 25,336	$ —	$ 165,486

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3 [(b)]	Dec. 31, 2013
Private equity investments	$ 33,250	$ 24,201	$ —	$ 5,245	$ —	$ 62,696
Real estate	39,074	31,626	(18,622)	5,290	—	57,368
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$ 104,600	$ 55,827	$ (18,622)	$ 10,535	$ (32,276)	$ 120,064

(a) Gains and losses are deferred as a component of the regulatory asset for nuclear decommissioning.

(b) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2015:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$ —	$ —	$ —	$ 21,356	$ 21,356
U.S. corporate bonds	—	16,005	51,384	(2,113)	65,276
International corporate bonds	—	2,787	9,382	632	12,801
Municipal bonds	153	264	17,814	33,358	51,589
Asset-backed securities	—	—	2,830	—	2,830
Mortgage-backed securities	—	—	—	11,621	11,621
Debt securities	$ 153	$ 19,056	$ 81,410	$ 64,854	$ 165,473

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2015, accumulated other comprehensive losses related to interest rate derivatives included $3.6 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

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

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

At Dec. 31, 2015, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2015 and 2014.

At Dec. 31, 2015, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.2 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) [(a)(b)]	**2015**	**2014**
MWh of electricity	50,487	56,361
MMBtu of natural gas	20,874	927
Gallons of vehicle fuel	141	282

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ 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. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At Dec. 31, 2015, two of Xcel Energy's 10 most significant counterparties for these activities, comprising $18.8 million or 9 percent of this credit exposure, had investment grade credit ratings from S&P's, Moody's or Fitch Ratings. Six of the 10 most significant counterparties, comprising $66.3 million or 30 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. The remaining two most significant counterparties, comprising $11.3 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

***Financial Impact of Qualifying Cash Flow Hedges* —** The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2015	2014	2013
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (57,628)	$ (59,753)	$ (61,241)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(70)	(163)	12
After-tax net realized losses on derivative transactions reclassified into earnings	2,836	2,288	1,476
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (54,862)	$ (57,628)	$ (59,753)

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2015, 2014 and 2013, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Losses Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 4,515 (a)	$ —	$ —
Vehicle fuel and other commodity	(116)	—	131 (b)	—	—
Total	$ (116)	$ —	$ 4,646	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ (7,286) (c)
Electric commodity	—	(18,543)	—	16,338 (d)	—
Natural gas commodity	—	(16,163)	—	15,694 (e)	(11,840) (e)
Total	$ —	$ (34,706)	$ —	$ 32,032	$ (19,126)

	Year Ended Dec. 31, 2014				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 3,836 [a]	$ —	$ —
Vehicle fuel and other commodity	(266)	—	(55) [b]	—	—
Total	$ (266)	$ —	$ 3,781	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 881 [c]
Electric commodity	—	(8,306)	—	(9,036) [d]	—
Natural gas commodity	—	5,166	—	(13,997) [e]	(13,220) [e]
Other commodity	—	—	—	—	643 [c]
Total	$ —	$ (3,140)	$ —	$ (23,033)	$ (11,696)

	Year Ended Dec. 31, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and(Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 4,107 [a]	$ —	$ —
Vehicle fuel and other commodity	29	—	(90) [b]	—	—
Total	$ 29	$ —	$ 4,017	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 11,221 [c]
Electric commodity	—	75,817	—	(52,796) [d]	—
Natural gas commodity	—	(3,088)	—	5,019 [e]	(6,589) [d]
Total	$ —	$ 72,729	$ —	$ (47,777)	$ 4,632

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts for the year ended Dec. 31, 2015 included $1.1 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses for the years ended Dec. 31, 2014 and 2013 were immaterial. The remaining settlement losses for the years ended Dec. 31, 2015, 2014 and 2013 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2015, 2014 and 2013. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. At Dec. 31, 2015 and 2014, there were no derivative instruments with contract provisions that required the posting of collateral or settlement of applicable outstanding contracts if the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2015 and 2014.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2015:

	Dec. 31, 2015					
	Fair Value					
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Counterparty Netting [b]**	**Total**
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 225	$ 10,620	$ 1,250	$ 12,095	$ (5,865)	$ 6,230
Electric commodity	—	—	21,421	21,421	(4,088)	17,333
Natural gas commodity	—	496	—	496	(303)	193
Total current derivative assets	$ 225	$ 11,116	$ 22,671	$ 34,012	$ (10,256)	23,756
PPAs [a]						10,086
Current derivative instruments						$ 33,842
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 27,416	$ —	$ 27,416	$ (6,555)	$ 20,861
Total noncurrent derivative assets	$ —	$ 27,416	$ —	$ 27,416	$ (6,555)	20,861
PPAs [a]						30,222
Noncurrent derivative instruments						$ 51,083

(Thousands of Dollars)	Dec. 31, 2015 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 205	$ —	$ 205	$ —	$ 205
Other derivative instruments:						
Commodity trading	152	7,866	555	8,573	(6,904)	1,669
Electric commodity	—	—	4,088	4,088	(4,088)	—
Natural gas commodity	—	5,407	—	5,407	(303)	5,104
Total current derivative liabilities	$ 152	$ 13,478	$ 4,643	$ 18,273	$ (11,295)	6,978
PPAs [a]						22,861
Current derivative instruments						$ 29,839
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Commodity trading	$ —	$ 19,898	$ —	$ 19,898	$ (9,780)	$ 10,118
Total noncurrent derivative liabilities	$ —	$ 19,898	$ —	$ 19,898	$ (9,780)	10,118
PPAs [a]						158,193
Noncurrent derivative instruments						$ 168,311

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $4.3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy’s derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2014:

(Thousands of Dollars)	Dec. 31, 2014 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 14,326	$ 4,732	$ 19,058	$ (3,240)	$ 15,818
Electric commodity	—	—	62,825	62,825	(11,402)	51,423
Natural gas commodity	—	381	—	381	(22)	359
Total current derivative assets	$ —	$ 14,707	$ 67,557	$ 82,264	$ (14,664)	67,600
PPAs [a]						18,123
Current derivative instruments						$ 85,723
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 17,617	$ —	$ 17,617	$ (4,151)	$ 13,466
Total noncurrent derivative assets	$ —	$ 17,617	$ —	$ 17,617	$ (4,151)	13,466
PPAs [a]						40,309
Noncurrent derivative instruments						$ 53,775

(Thousands of Dollars)	Dec. 31, 2014 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 118	$ —	$ 118	$ —	$ 118
Other derivative instruments:						
Commodity trading	—	7,974	—	7,974	(7,974)	—
Electric commodity	—	—	11,402	11,402	(11,402)	—
Natural gas commodity	—	548	—	548	(21)	527
Total current derivative liabilities	$ —	$ 8,640	$ 11,402	$ 20,042	$ (19,397)	645
PPAs [a]						20,987
Current derivative instruments						$ 21,632
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 102	$ —	$ 102	$ —	$ 102
Other derivative instruments:						
Commodity trading	—	6,890	—	6,890	(6,033)	857
Natural gas commodity	—	35	—	35	—	35
Total noncurrent derivative liabilities	$ —	$ 7,027	$ —	$ 7,027	$ (6,033)	994
PPAs [a]						182,942
Noncurrent derivative instruments						$ 183,936

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2015, 2014 and 2013:

(Thousands of Dollars)	Year Ended Dec. 31 2015	2014	2013
Balance at Jan. 1	$ 56,155	$ 41,660	$ 16,649
Purchases	63,712	135,008	61,474
Settlements	(69,754)	(145,974)	(45,199)
Transfers out of Level 3	—	(1,093)	—
Net transactions recorded during the period:			
Gains recognized in earnings [a]	1,533	10,692	3,947
(Losses) gains recognized as regulatory assets and liabilities	(33,618)	15,862	4,789
Balance at Dec. 31	$ 18,028	$ 56,155	$ 41,660

(a) These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2015 and 2013. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

As of Dec. 31, 2015 and 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

	2015		2014	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 13,147,740	$ 14,094,744	$ 11,757,360	$ 13,360,236

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2015 and 2014, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

12. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case was based on a ROE of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million, or 6.9 percent, in 2014 and an additional $98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan. In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund. In 2014, NSP-Minnesota revised its requested rate increase to $115.3 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $221.3 million.

In May 2015, the MPUC ordered a total increase of $166.1 million, or 5.9 percent, consisting of $58.9 million and $125.2 million in 2014 and 2015, respectively, and an $18.0 million adjustment related to disallowance of certain Monticello LCM/EPU costs. The MPUC also approved a three-year, decoupling pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of changes in electric sales due to conservation and weather variability for these classes.

In July 2015, the MPUC deliberated on requests for reconsideration and determined the Monticello EPU project was not yet used-and-useful, as final approval related to the full EPU uprate condition had not been received from the NRC as of June 30, 2015. As a result, $13.8 million was excluded from final rates. Monticello subsequently received final NRC compliance approval in July 2015. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decisions resulted in a total estimated 2014 and 2015 annual rate increase of $149.4 million, or 5.3 percent.

The following table outlines the impact of the MPUC's July decision:

(Millions of Dollars)	MPUC July Decision
2014 and 2015 step increase - based on MPUC May order	$ 166.1
Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net	0.2
Total 2014 and 2015 step increase	$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated revenue impact	$ 145.8

NSP-Minnesota – Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below.

Request (Millions of Dollars)	2016	2017	2018
Rate request	$ 194.6	$ 52.1	$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	$ 163.7	$ 44.9	N/A
Rate base	$ 7,800	$ 7,700	$ 7,700

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years.

In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016. The MPUC also required NSP-Minnesota to file supplemental direct testimony addressing costs associated with the LCM at the PI nuclear plant. NSP-Minnesota filed supplemental testimony in January 2016 demonstrating that the capital work at PI, including the LCM, is required during the rate case period, higher costs associated with the LCM are necessary to operate the plant through the end of its licensed life and recovery of these costs will result in reasonably priced energy for customers.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	2016	2017	2018	Total
2014 multi-year rate case items:				
Excess depreciation reserve	$ 26.0	$ 51.0	$ —	$ 77.0
DOE settlement	25.7	—	—	25.7
Monticello LCM/EPU	11.2	(1.6)	(1.5)	8.1
	62.9	49.4	(1.5)	110.8
Additional items:				
Capital investments	128.7	12.8	44.6	186.1
Property taxes	30.2	7.6	5.2	43.0
NOL carryforwards	(6.3)	(24.5)	(6.5)	(37.3)
Other costs	(20.9)	6.8	8.6	(5.5)
	131.7	2.7	51.9	186.3
Total rate request	$ 194.6	$ 52.1	$ 50.4	$ 297.1

The next steps in the procedural schedule are expected to be as follows:

- Intervenors' direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- ALJ report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW. The Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

In March 2015, the MPUC voted to allow for full recovery, including a return, on approximately $415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used-and-useful for 2014. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Minnesota – 2016 TCR Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of $19.2 million of 2016 transmission investment costs not included in electric base rates. This filing included an option to keep approximately $59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 within the TCR rider or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. In November 2015, NSP-Minnesota submitted an update to its TCR filing in which it confirmed that it was requesting the MPUC approve keeping the two CapX2020 projects in the TCR rider, increasing the revenue requirements to $78.3 million, until the conclusion of the 2016 Minnesota electric rate case.

Recently Concluded Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota Infrastructure Rider —In December 2015, the SDPUC approved recovery of $10.2 million through the infrastructure rider effective beginning Jan. 1, 2016. As part of the South Dakota 2015 electric rate case, the infrastructure rider was refreshed with new projects and was also expanded as a mechanism to allow for possible recovery of other investments related to generation, transmission, and distribution.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years and in 2015 extended the mechanisms to the 2016 program year. The estimated average annual electric and natural gas incentives are $30.6 million and $3.6 million, respectively, based on the approved savings goals.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In July 2015, the MPUC approved NSP-Minnesota's 2014 CIP electric and natural gas financial incentives totaling $40.1 million and $5.8 million, respectively.
- In addition, the MPUC approved NSP-Minnesota's proposed 2015 to 2016 electric and natural gas CIP riders. NSP-Minnesota estimates 2016 recovery of $21.5 million of electric CIP expenses and $9.2 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated $86.9 million and $3.7 million through electric and gas base rates, respectively.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In October 2015, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately $15.5 million from Minnesota gas utility customers beginning April 1, 2016. This request includes $1.9 million in over-recovery from 2015 and $4.5 million of deferred sewer separation and integrity management costs which is the 2016 portion of a five year amortization.

An MPUC decision is expected in the second half of 2016.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

NSP-Wisconsin – Wisconsin 2016 Electric and Gas Rate Case — In May 2015, NSP-Wisconsin filed a request with the PSCW seeking an increase in annual electric rates of $27.4 million, or 3.9 percent, and an increase in natural gas rates of $5.9 million, or 5.0 percent, effective Jan. 1 2016. The rate filing was based on a 2016 forecast test year, a ROE of 10.2 percent, an equity ratio of 52.5 percent and a forecasted average rate base of approximately $1.2 billion for the electric utility and $111.2 million for the natural gas utility.

In December 2015, the PSCW approved an electric rate increase of approximately $7.6 million, or 1.1 percent, and a natural gas rate increase of $4.2 million, or 3.6 percent, based on a 10.0 percent ROE and an equity ratio of 52.5 percent. New rates went into effect in January 2016. As shown below, NSP-Wisconsin received approximately 65 percent of the non-fuel and purchased power portion of its requested electric rate increase and 71 percent of its requested natural gas rate increase.

The major components of the requested rate increases and the PSCW's approval are summarized as follows:

Electric Rate Request (Millions of Dollars)	NSP-Wisconsin Request	PSCW Approval
Capital investments	$ 23.0	$ 13.9
ROE & other capital structure adjustments	—	(3.8)
Generation and transmission expenses (excluding fuel and purchased power)	37.2	42.7
O&M expenses	11.1	3.2
Sales forecast	(27.0)	(27.0)
Rate increase - non-fuel and purchased power	44.3	29.0
Rate reduction - fuel and purchased power	(16.9)	(21.4)
Total electric rate increase	$ 27.4	$ 7.6

Natural Gas Rate Request (Millions of Dollars)	NSP-Wisconsin Request	PSCW Approval
Capital investments	$ 3.7	$ 3.7
ROE & other capital structure adjustments	—	(0.4)
O&M expenses	3.2	1.9
Environmental remediation expenses	2.9	2.9
Sales forecast	(3.9)	(3.9)
Total natural gas rate increase	$ 5.9	$ 4.2

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2015 Multi-Year Gas Rate Case — In March 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by $66.2 million over three years. The request was based on a HTY ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the periods in the MYP and an equity ratio of 56 percent. In addition, PSCo requested an extension of its PSIA rider through 2020 to recover costs associated with its pipeline integrity efforts. The rider would recover incremental revenue of $42.8 million over three years.

In July 2015, PSCo filed rebuttal testimony with adjustments and modified recovery between base rates and the PSIA rider. The revised request is summarized below:

(Millions of Dollars)	2015	2016 Step	2017 Step
PSCo's filed base rate request	$ 40.5	$ 7.6	$ 18.1
Shift O&M expenses between PSIA and base rates	—	7.0	6.4
Rebuttal corrections and adjustments	—	—	(7.7)
Total base rate increase	$ 40.5	$ 14.6	$ 16.8
Incremental PSIA rider revenues	(0.1)	14.7	21.7
Total revenue impact from rebuttal	$ 40.4	$ 29.3	$ 38.5
Requested ROE	10.1%	10.1%	10.3%
Rate base	$ 1,260	$ 1,310	$ 1,360

In November 2015, the ALJ issued his recommended decision, which reflected a 2014 HTY with a 13-month average rate base, the Cherokee pipeline investment adjusted to year-end rate base, a ROE of 9.5 percent and an equity ratio of 56.51 percent. In addition, the ALJ's recommendation included a three-year extension (2016 through 2018) of the PSIA rider with all O&M expenses transferred to base rates as well as certain other projects shifting between the PSIA rider and base rates, beginning January 2016. The ALJ also recommended that certain expenses, including property taxes and damage prevention costs that exceed the 2014 HTY level, be deferred. He further recommended a pension cost tracker and certain other deferral related items.

In February 2016, the CPUC issued their written order. Key matters are as follows:

- 2014 HTY, with a 13-month average rate base, with the exception of the Cherokee pipeline which is included at a year-end level;
- Extension of the PSIA rider through 2018 with all O&M expenses transferred to base rates;
- A ROE of 9.5 percent; and
- An equity ratio of 56.51 percent.

The following table reflects the ALJ's position and the CPUC's written order (estimated):

(Millions of Dollars)	ALJ	CPUC's Written Order
PSCo's filed 2015 base rate request [(a)]	$ 40.5	$ 40.5
ROE	(7.8)	(7.8)
Capital structure and cost of debt	(0.5)	(0.5)
Cherokee pipeline adjustment	4.1	4.1
Move to 2014 HTY	(14.1)	(14.1)
O&M expenses	(3.0)	(2.4)
Other, net	(1.1)	(1.1)
Overall recommended rate increase	$ 18.1	$ 18.7

(a) The ALJ's recommendation and the CPUC's written order also includes approximately $20.0 million of PSIA costs be transferred to base rates, effective Jan. 1, 2016.

The ALJ's recommendation, as well as the CPUC's written order for the PSIA rider, are as follows (estimated):

	ALJ		CPUC's Written Order	
(Millions of Dollars)	2016	2017	2016	2017
PSCo's filed incremental PSIA request	$ 21.7	$ 21.2	$ 21.7	$ 21.2
Transfer PSIA costs to base rates	(20.5)	—	(20.5)	—
PSIA cost recovery remaining in base	(4.3)	—	(4.3)	—
Projects not recovered through the PSIA	(3.6)	(2.0)	(3.3)	(0.8)
ROE and capital structure	(0.3)	(1.6)	(0.3)	(1.6)
Total	$ (7.0)	$ 17.6	$ (6.7)	$ 18.8

The following table summarizes the estimated annual pre-tax impact of the CPUC's written order:

(Millions of Dollars)	2015	2016	2017
Base rate increase	$ 18.7	$ 19.7	$ —
Incremental PSIA rider revenues	(0.2)	(6.7)	18.8
Expense deferrals, net amortization [(a)]	(3.6)	1.5	5.2
Estimated pre-tax impact	$ 14.9	$ 14.5	$ 24.0

(a) Deferral and amortization impacts relate primarily to recognition of accelerated amortization of prepaid pension assets and deferrals of pension expense in excess of the amount approved in the prior general gas rate case.

Interim rates, subject to refund, went into effect Oct. 1, 2015. PSCo has recognized management's best estimate of the potential customer refund obligation.

PSCo – Colorado 2015 Steam Rate Case — In November 2015, PSCo filed a request to increase Colorado retail steam rates by $3.5 million in 2016. In December 2015, the CPUC approved the filed request which recovers costs related to upgrades for the state steam plant as well as the Zuni Station and permits use of the Zuni Station exclusively for steam business. Final rates are implemented in two steps with $2.8 million, which began on Jan. 1, 2016, and the remaining $0.7 million which will be effective Nov. 1, 2016.

PSCo – Annual Electric Earnings Test — In February 2015, in the Colorado 2014 Electric Rate Case, the CPUC approved an annual earnings test in which PSCo shares with customers earnings that exceed the authorized ROE threshold of 9.83 percent for 2015 through 2017. As of Dec. 31, 2015, PSCo has recognized management's best estimate of the expected customer refund obligation for the 2015 earnings test of $15 million. PSCo will file its 2015 earnings test with the CPUC in April 2016. The final sharing obligation will be based on the CPUC approved tariff and could vary from the current estimate.

Electric, Purchased Gas and Resource Adjustment Clauses

DSM and the DSMCA — Energy efficiency and DSM costs are recovered through a combination of the DSMCA riders and base rates. DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are trued-up in the following year. Savings goals were 384 GWh in 2014 and 400 GWh in 2015 with incentives awarded in the year following plan achievements. PSCo is able to earn $5 million upon reaching its annual savings goal along with an incentive on five percent of net economic benefits up to a maximum annual incentive of $30 million. For the years 2016 through 2020, the annual electric energy savings goal is 400 GWh per year with an annual spending limit of $84.3 million.

In July 2015, the CPUC approved PSCo's 2015-2016 DSM plan:

- A 2015 DSM electric budget of $81.6 million and a natural gas budget of $13.1 million; and
- A 2016 DSM electric budget of $78.7 million and a natural gas budget of $13.6 million.

REC Sharing — In 2011, the CPUC approved margin sharing on stand-alone REC transactions at 10 percent to PSCo and 90 percent to customers for 2014. In 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. PSCo credited to the RESA regulatory liability balance approximately $5.5 million and $0.6 million in 2015 and 2014, respectively. The cumulative credit to the RESA regulatory liability balance was $110.6 million and $105.1 million at Dec. 31, 2015 and Dec. 31, 2014, respectively. The credits include the customers' share of REC trading margins and the unspent share of carbon offset funds. The current sharing mechanism, without modification, extends through 2017.

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on a HTY ending June 2014, adjusted for known and measurable changes, a ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent.

SPS requested a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014. In June 2015, SPS revised its requested rate increase to $42.1 million.

In December 2015, the PUCT made the following decisions:

- Disallowed SPS' proposed adjustment to jurisdictional allocation factors to reflect Golden Spread Electric Cooperative, Inc.'s (Golden Spread's) wholesale load reductions from 500 MW to 300 MW, effective June 1, 2015;
- Disallowed incentive compensation;
- Approved an equity ratio of 51.00 percent instead of the actual 53.97 percent; and
- A ROE of 9.70 percent.

The following table reflects the ALJs' position and PUCT's decision.

(Millions of Dollars)	ALJs' Proposal for Decision	PUCT Decision
SPS' revised rate request	$ 42.1	$ 42.1
Investment for capital expenditures — post-test year adjustments	(8.9)	(8.9)
Lower ROE	(6.3)	(6.3)
Lower capital structure	—	(3.7)
Annual incentive compensation	(0.2)	(0.3)
O&M expense adjustments	(4.6)	(4.6)
Depreciation expense	(2.7)	(2.7)
Property taxes	(0.9)	(0.9)
Revenue adjustments	(1.1)	(1.6)
Wholesale load reductions	—	(11.5)
SPP transmission expansion plan	(4.2)	(4.2)
Other, net	1.4	(1.2)
Total, gross of rate case expenses	$ 14.6	$ (3.8)
Adjustment to move rate case expenses to a separate docket	(0.2)	(0.2)
Total, net of rate case expenses	$ 14.4	$ (4.0)
New depreciation rates	(11.2)	(11.2)
Earnings impact	$ 3.2	$ (15.2)

In January 2016, SPS filed its motion for rehearing on capital structure, incentive compensation and known and measurable adjustments, including wholesale load reductions and post test-year capital additions. On Feb. 11, 2016, the PUCT orally denied requests for rehearing. SPS plans to file a second motion for rehearing within 20 days of the date of the PUCT's written order.

SPS – Texas 2016 Electric Rate Case — On Feb. 16, 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the PUCT requesting an overall increase in annual base rate revenue of approximately $71.9 million, or 14.4 percent. The filing is based on a HTY ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately $1.7 billion, and an equity ratio of 53.97 percent.

As part of its request, SPS included estimated information regarding increases and decreases in SPS' cost of service, including certain expenses, capital investments, cost of capital and sales for the period of Oct. 1, 2015 through Dec. 31, 2015. Subsequent to the filing, (i.e., 45 days), the estimated information will be updated to reflect actual results.

The following table summarizes the net request:

(Millions of Dollars)	Request
Capital expenditure investments	$ 38.6
Change in jurisdictional allocation factors	10.9
Changes in ROE and capital structure	11.7
Estimated rate case expenses [(a)]	4.5
Other, net	6.2
Total	$ 71.9

(a) SPS anticipates rate case expenses, for this proceeding, to be separated from the request for consideration in a separate docket.

The final rates established at the end of the case will be made effective retroactive to July 20, 2016 and SPS will be entitled to collect a surcharge for usage from July 20, 2016 through the date SPS implements final rates. A PUCT decision is anticipated in the first quarter of 2017.

Pending Regulatory Proceedings — NMPRC

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed a New Mexico electric rate case with the NMPRC for a net increase in base rates of approximately $24.3 million. The proposed net amount reflects an increase in non-fuel base rates of $45.4 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power adjustment clause. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric jurisdictional rate base of approximately $734 million and an equity ratio of 53.97 percent.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	Request
2015 base period deficiency	$ 19.7
Capital expenditures — post-test year adjustments	12.3
Depreciation, higher rates reflecting changes in depreciable lives, interim retirements and net salvage	3.7
Transmission revenue and expense, including charges paid to SPP for construction of regionally shared transmission projects	2.0
ROE, reflecting an increase from 9.96 percent to 10.25 percent	1.6
Rider revenue adjustments - gross receipts tax	1.3
Other, net	4.8
Requested rate increase	$ 45.4

The next steps in the procedural schedule are expected to be as follows:

- Settlement conference — Feb. 29, 2016;
- Staff and intervenor direct testimony — April 1, 2016;
- Rebuttal testimony — April 18, 2016; and
- Evidentiary hearing begins — April 28, 2016.

A NMPRC decision and implementation of final rates is anticipated in the second half of 2016.

In response to the original 2015 electric rate case previously dismissed, SPS has appealed that decision to the New Mexico Supreme Court. SPS and the NMPRC have filed a joint agreed motion to dismiss the appeal with the New Mexico Supreme Court. The motion provides for the case to be remanded to the NMPRC for entry of an order affirming SPS' right to use a FTY that begins up to 13 months after SPS files a rate case. SPS will not resume the previously dismissed rate case and will proceed with the October 2015 rate case.

Pending and Recently Concluded Regulatory Proceedings — FERC and Other

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO TOs, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013.

Subsequently, the FERC adopted a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

The ROE complaint was set for full hearing procedures. The complainants and intervenors filed testimony recommending a ROE between 8.67 percent and 9.54 percent. The FERC staff recommended a ROE of 8.68 percent. The MISO TOs recommended a ROE not less than 10.8 percent. In December 2015, an ALJ initial decision was issued recommending a ROE of 10.32 percent. Briefs on exceptions challenging the ALJ recommendation were filed in January 2016. A FERC order is expected to be issued later in 2016.

Certain MISO TOs separately requested FERC approval of a 50 basis point ROE adder for RTO membership, which was approved effective Jan. 6, 2015, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. Certain intervenors sought rehearing of the FERC order granting the ROE adder and FERC action is pending.

In February 2015, certain intervenors filed a second complaint to reduce the MISO region ROE to 8.67 percent, prior to an adder. FERC set the second complaint for hearings, and established a refund effective date of Feb. 12, 2015. The complainants and intervenors filed direct testimony in September 2015, the MISO TOs filed answering testimony in October 2015 and FERC staff filed testimony in November 2015. In January 2016, all parties updated their ROE analyses. The complainants and intervenors recommended ROEs between 8.72 percent and 9.32 percent while FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.96 percent. Hearings were held before an ALJ in February 2016. An ALJ initial decision is expected in June 2016 with a FERC decision expected in late 2016 or 2017.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of Dec. 31, 2015. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between $8 million and $10 million annually for the NSP System.

SPS – Global Settlement Agreement **—** In August 2015, SPS, Golden Spread, four New Mexico Cooperatives, West Texas Municipal Power Agency, Public Service Company of New Mexico (PNM) and Tri-County Electric Cooperative, Inc. filed a settlement agreement with the FERC that would provide a comprehensive resolution of nine pending matters in dispute between SPS and these wholesale production and transmission customers, including the 2013 SPS complaint orders and three pending ROE complaints. In October 2015, the FERC issued an order approving the settlement agreement. As a result of the settlement, SPS issued refunds to Golden Spread and PNM of $49.1 million, but recognized a reversal of previously recorded reductions in revenue of approximately $7.9 million in the fourth quarter of 2015. The settlement provides a ROE for production services of 10.0 percent and transmission services of 10.5 percent, beginning Oct. 20, 2014, and subject to a moratorium on filings for ROE changes, effective prior to Jan. 1, 2020. On Jan. 29, 2016, the FERC approved the SPS compliance filings required by the settlement and FERC order.

Sale of Texas Transmission Assets **—** In March 2015, SPS reached an agreement to sell certain segments of SPS' transmission lines to Oncor Electric Delivery Company LLC. In November 2015, the transaction closed with the required regulatory approvals and SPS recognized a $3.9 million pre-tax gain after the impacts of sharing with Texas retail customers.

SPP Open Access Transmission Tariff (OATT) Upgrade Costs **—** Under the SPP OATT, costs of participant-funded transmission upgrades may be recovered, in part, from other SPP customers whose transmission service is dependent upon capacity enabled by the upgrades. To date, SPP has not charged its customers any amounts attributable to these upgrades. SPP recently indicated it may attempt to quantify and assess charges beginning in late 2016, including amounts for prior periods. Due to the limited information available and lack of historical precedent, the potential loss, if any, is not currently estimable. No accrual has been recorded for this matter.

13. Commitments and Contingencies

Commitments

Capital Commitments **—** Xcel Energy has made commitments in connection with a portion of its projected capital expenditures. Xcel Energy's capital commitments primarily relate to the following major projects:

PSCo Gas Transmission Integrity Management Programs **—** PSCo is proactively identifying and addressing the safety and reliability of natural gas transmission pipelines. The pipeline integrity efforts include primarily pipeline assessment and maintenance projects.

PSCo Electric Distribution Integrity Management Programs **—** PSCo is assessing aging infrastructure for distribution assets and replacing worn components to increase system performance.

SPS Transmission NTC — SPS has accepted NTCs for several hundred miles of transmission line and related substation projects based on needs identified through SPP's various planning processes, including those associated with economics, reliability, generator interconnection or the load addition processes. Most significant are the 345 KV transmission line from TUCO to Yoakum County to Hobbs Plant and the Hobbs Plant to China Draw 345 KV transmission line.

Fuel Contracts — Xcel Energy has entered into various long-term commitments 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 2016 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for Xcel Energy under these contracts as of Dec. 31, 2015 are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2016	$ 824.4	$ 112.2	$ 285.4	$ 282.0
2017	483.0	112.3	132.2	254.9
2018	227.8	62.7	181.0	154.5
2019	42.7	124.1	187.6	113.8
2020	44.4	46.9	203.4	101.6
Thereafter	334.9	599.2	409.5	1,044.2
Total	$ 1,957.2	$ 1,057.4	$ 1,399.1	$ 1,951.0

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. 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.

PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $230.6 million, $229.8 million and $217.0 million in 2015, 2014 and 2013, respectively. At Dec. 31, 2015, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy [(a)]
2016	$ 191.0	$ 106.9
2017	165.8	91.8
2018	129.1	93.2
2019	83.6	98.7
2020	68.1	105.4
Thereafter	362.5	662.5
Total	$ 1,000.1	$ 1,158.5

(a) Excludes contingent energy payments for renewable energy PPAs.

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — Xcel Energy leases a variety of equipment and facilities used in the normal course of business. Three of these leases qualify as capital leases and are accounted for accordingly. The assets and liabilities at the inception of a capital lease are recorded at the lower of fair market value or the present value of future lease payments and are amortized over the term of the contract.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy Inc. has a 50 percent ownership interest in WYCO. WYCO generally leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had $132.9 million and $138.9 million of capital lease obligations recorded for the arrangement as of Dec. 31, 2015 and 2014, respectively. Xcel Energy Inc. eliminates 50 percent of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital leases as cost of natural gas sold and transported on the consolidated statements of income. Total amortization expenses under capital lease assets were approximately $8.2 million, $7.2 million and $6.3 million for 2015, 2014 and 2013, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Gas storage facilities	$ 200.5	$ 200.5
Gas pipeline	20.7	20.7
Property held under capital leases	221.2	221.2
Accumulated depreciation	(57.2)	(49.0)
Total property held under capital leases, net	$ 164.0	$ 172.2

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately $265.3 million, $271.9 million and $242.1 million for 2015, 2014 and 2013, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of $223.6 million, $228.2 million and $197.7 million in 2015, 2014 and 2013, respectively, recorded to electric fuel and purchased power expenses.

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases in accordance with the applicable accounting guidance.

Future commitments under operating and capital leases are:

(Millions of Dollars)	Operating Leases	PPA [(a)] [(b)] Operating Leases	Total Operating Leases	Capital Leases
2016	$ 24.6	$ 217.0	$ 241.6	$ 17.1
2017	22.0	208.7	230.7	15.1
2018	21.5	210.0	231.5	14.7
2019	25.9	227.8	253.7	14.5
2020	20.8	241.3	262.1	14.3
Thereafter	175.0	2,135.2	2,310.2	258.8
Total minimum obligation				334.5
Interest component of obligation				(236.9)
Present value of minimum obligation				$ 97.6 [(c)]

(a) Amounts do not include PPAs accounted for as executory contracts.
(b) PPA operating leases contractually expire through 2039.
(c) Future commitments exclude certain amounts related to Xcel Energy's 50 percent ownership interest in WYCO.

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

PPAs **—**Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the independent power producing entity.

Xcel Energy has determined that certain independent power producing entities are variable interest entities. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy's utility subsidiaries had approximately 3,698 MW of capacity under long-term PPAs as of Dec. 31, 2015, and 2014 with entities that have been determined to be variable interest entities. These agreements have expiration dates through 2033.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO under contracts for those facilities that expire in December 2016 and December 2017, respectively. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

No significant financial support has been, or is required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs. SPS has determined that TUCO is a variable interest entity. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. These limited partnerships are designed to qualify for low-income housing tax credits. Eloigne and NSP-Wisconsin generally receive a larger allocation of the tax credits than the general partners at inception of the arrangements. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne, NSP-Wisconsin and the general partner of each limited partnership. Xcel Energy's risk of loss is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin. Mortgage-backed debt typically comprises the majority of the financing at inception of each limited partnership and is paid over the life of the limited partnership arrangement. Obligations of the limited partnerships are generally secured by the housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy Inc. or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy Inc. or its subsidiaries.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Current assets	$ 6,274	$ 6,609
Property, plant and equipment, net	51,480	53,047
Other noncurrent assets	1,394	1,503
Total assets	$ 59,148	$ 61,159
Current liabilities	$ 7,540	$ 7,774
Mortgages and other long-term debt payable	31,082	31,207
Other noncurrent liabilities	644	619
Total liabilities	$ 39,266	$ 39,600

Technology Agreements — Xcel Energy has a contract that extends through December 2019 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50 percent of the contract value for early termination. Xcel Energy capitalized or expensed $109.5 million, $111.3 million and $90.3 million associated with the IBM contract in 2015, 2014 and 2013, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $17.3 million, $27.3 million and $23.7 million associated with the Accenture contract in 2015, 2014 and 2013, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2016	$ 34.4	$ 10.0
2017	34.4	10.5
2018	33.5	10.7
2019	33.5	10.8
2020	—	11.0
Thereafter	—	—

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Dec. 31, 2015 and 2014, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding as of Dec. 31, 2015:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of customer loans for the Farm Rewiring Program [(a)]	NSP-Wisconsin	$ 1.0	$ 0.1	(e)
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases [(b)]	Xcel Energy Inc.	6.7	—	(f)
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement [(c)]	NSP-Minnesota	4.8	—	(g)
Total guarantees issued		$ 12.5	$ 0.1	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(d)]	Xcel Energy Inc.	$ 41.3	(i)	(h)

(a) The term of this guarantee expires in 2020, which is the final scheduled repayment date for the loans. As of Dec. 31, 2015, no claims had been made by the lender.

(b) The term of this guarantee expires in 2017 when the associated leases expire.

(c) The terms of this guarantee expires in 2019 when the associated lease expires.

(d) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(e) The debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Nonperformance and/or nonpayment.

(g) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

(h) Failure of any one of Xcel Energy Inc.'s utility subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy Inc. and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(i) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

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

Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by Xcel Energy Inc.'s subsidiaries or their predecessors, or other entities; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to be a PRP that sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Site) includes property owned by NSP-Wisconsin, previously operated by a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park); and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

In 2010, the EPA issued its Record of Decision (ROD), including their preferred remedy for the Sediments which is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). A wet conventional dredging only remedy (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study, is another possibility.

In 2012, under a settlement agreement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site). Fieldwork began in 2012 and continues. Excavation and containment remedies are complete. A long-term groundwater pump and treatment program is now underway. The final design was approved by the EPA in late 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately $65 million, of which approximately $47 million has already been spent.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and which remedy will be implemented. The EPA's ROD includes estimates that the cost of the Hybrid Remedy is between $63 million and $77 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower. NSP-Wisconsin believes the Hybrid Remedy is not safe or feasible to implement. In 2015, NSP-Wisconsin constructed a breakwater at the site to serve as wave attenuation and containment for a wet dredge pilot study and full scale sediment remedy at the site. The wet dredge pilot study is anticipated to commence in spring 2016.

As a result of litigation and settlements approved by the U.S. District Court for the Western District of Wisconsin in 2015, three other PRPs have contributed $15.9 million to the remediation of the site. Settlements in principle were also reached with the City of Ashland and the County of Ashland in January 2016, and NSP-Wisconsin anticipates that its litigation efforts against other PRPs are complete.

At Dec. 31, 2015 and 2014, NSP-Wisconsin had recorded a liability of $94.4 million and $107.6 million, respectively, for the Site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $17.0 million and $28.9 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented and whether federal or state funding may be directed to help offset remediation costs at the Site.

NSP-Wisconsin has deferred the estimated site remediation costs as a regulatory asset. The PSCW has consistently authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In a December 2012 decision, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period, and to apply a three percent carrying cost to the unamortized regulatory asset. In December 2015, the PSCW approved NSP-Wisconsin's 2016 rate case request for an increase to the annual recovery for MGP clean-up costs from $4.7 million to $7.6 million.

Fargo, N.D. MGP Site — In May 2015, in connection with a city water main replacement and street improvement project in Fargo, N.D., underground pipes, tars and impacted soils, which may be related to a former MGP site operated by NSP-Minnesota or a prior company, were discovered. After initial reports and discussions with the City of Fargo and the North Dakota Department of Health, NSP-Minnesota removed the impacted soils and other materials from the project area. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. At this time, NSP-Minnesota's investigation of the site is preliminary as information is still being gathered. In October 2015, NSP-Minnesota initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota will likely establish a scheduling order for the case in the first quarter of 2016.

As of Dec. 31, 2015, NSP-Minnesota had recorded a liability of $2.7 million related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota's potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In July 2015, NSP-Minnesota filed a request with the NDPSC for approval to initially defer the portion of investigation and response costs allocable to the North Dakota jurisdiction. In December 2015, the NDPSC approved NSP-Minnesota's request.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where regulated materials may have been deposited. Xcel Energy has identified seven sites across all of its service territories where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2016. Xcel Energy had accrued $2.1 million for all of these sites at Dec. 31, 2015 and 2014, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. Xcel Energy has recorded an estimate for final removal of the asbestos as an ARO. 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 not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In September 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. Xcel Energy estimates that the cost to comply with the new ELG rule for Colorado will range from $9 million to $21 million, and could change as Xcel Energy continues to assess alternate compliance technologies. Xcel Energy is in the process of evaluating whether the costs of compliance at NSP-Minnesota and NSP-Wisconsin could have a material impact on the results of operations, financial position or cash flows. The anticipated costs of compliance with the final rule at SPS are not expected to have a material impact on the results of operations, financial position or cash flows. Xcel Energy believes that compliance costs would be recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). For Xcel Energy, these requirements will primarily impact plants within the NSP-Minnesota service territory. The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. Xcel Energy estimates the likely cost for complying with impingement requirements may be incurred between 2016 and 2027 and is approximately $49 million with the majority needed for NSP-Minnesota. Xcel Energy believes at least six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to $194 million depending on the outcome of certain entrainment studies and cost-benefit analyses. Xcel Energy anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term "Waters of the U.S." will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. The rule went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

Air

GHG Emission Standard for Existing Sources (Clean Power Plan or CPP) **—** In October 2015, a final rule was published by the EPA for GHG emission standards for existing power plants. States must develop implementation plans by September 2016, with the possibility of an extension to September 2018, or the EPA will prepare a federal plan for the state. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA's state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The CPP is currently being challenged by multiple parties in the D.C. Circuit Court. In January 2016, the D.C. Circuit Court denied requests to stay the effectiveness of the rule as well as ordered expedited review of the CPP, with briefings to be completed and oral arguments held by June 2016. Following the D.C. Circuit Court's denial of motions for stay, multiple parties filed requests for stay with the U.S. Supreme Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. The stay will remain in effect until, first, the D.C. Circuit Court and then the U.S. Supreme Court have ruled on the challenges to the CPP.

Xcel Energy has undertaken a number of initiatives that reduce GHG emissions and respond to state renewable and energy efficiency goals. The CPP could require additional emission reductions in states in which Xcel Energy operates. If state plans do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. Until Xcel Energy has more information about SIPs or knows the requirements of the EPA's upcoming final rule on federal plans for the states that do not develop related plans, Xcel Energy cannot predict the costs of compliance with the final rule once it takes effect. Xcel Energy believes compliance costs will be recoverable through regulatory mechanisms. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the CPP or cost recovery is not provided in a timely manner, it could have a material impact on results of operations, financial position or cash flows.

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO_2 and NOx from utilities in the eastern half of the United States using an emissions trading program. For Xcel Energy, the rule applies in Minnesota, Wisconsin and Texas. CSAPR compliance in 2015 did not and 2016 is not expected to have a material impact on the results of operations, financial position or cash flows.

CSAPR was adopted to address interstate emissions impacting downwind states' attainment of the 1997 ozone NAAQS and the 1997 and 2006 particulate NAAQS. As the EPA revises the NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. If adopted as proposed, the ozone season emission budget for NOx in Texas would be reduced by approximately 14 percent, which may lead to increased cost to purchase emission allowances.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the BART requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In their first regional haze SIPs, Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the CACJA emission reduction plan as satisfying regional haze requirements for facilities included within the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at Hayden Unit 1 were placed into service in November 2015 and Hayden Unit 2 is expected to be placed into service in late 2016, at an estimated combined cost of $75.2 million, completing the pollution control equipment required on PSCo plants under the CACJA. PSCo anticipates these costs will be fully recoverable through regulatory mechanisms.

NSP-Minnesota

In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA supplemented its Minnesota SIP in 2012, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, the EPA approved the Minnesota SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2. The combustion controls were installed first and the scrubber upgrades were completed in December 2014, at a cost of $46.9 million. NSP-Minnesota has included these costs for recovery in rate proceedings.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In January 2016, the Eighth Circuit issued their opinion which upheld the EPA's approval of the Minnesota SIP.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. In December 2014, the EPA proposed to approve the BART portion of the Texas SIP, with the exception that the EPA would substitute CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that defers its approval of CSAPR compliance as BART until the EPA considers further adjustments to CSAPR emission budgets in relation to the 2012 particle NAAQS.

In May 2014, the EPA issued a request for information under the CAA related to SO_2 control equipment at Tolk Units 1 and 2. In December 2014, the EPA proposed to disapprove the reasonable progress portions of the Texas SIP and instead adopt a FIP. The EPA proposed to require dry scrubbers on both Tolk units to reduce SO_2 emissions to help achieve reasonable progress goals for Texas and Oklahoma national parks and wilderness areas. In January 2016, the EPA adopted a final rule establishing a FIP for the state of Texas. As part of this final rule, the EPA imposed SO_2 emission limitations that reflect the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately $600 million. SPS plans to appeal the EPA's decision. SPS believes these costs would be recoverable through regulatory mechanisms if required, and therefore does not expect a material impact on results of operations, financial position or cash flows.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota (Minnesota District Court) by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club.

In May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO_2 emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

After a public comment period, the EPA notified the Minnesota District Court, in July 2015, that the settlement agreement is final. The EPA has seven months to recommend and adopt a rule which will set the agreed-upon SO_2 emissions. In October 2015, the EPA proposed a rule that would set the agreed-upon SO_2 emission limits. No public comments were received on this proposal. A final rule is anticipated in March 2016. NSP-Minnesota does not anticipate the costs of compliance with the proposed settlement will have a material impact on the results of operations, financial position or cash flows.

Implementation of the NAAQS for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where Xcel Energy operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree the EPA is requiring states to evaluate areas in three phases. The first phase includes areas near PSCo's Pawnee plant and SPS' Tolk and Harrington plants. The Pawnee plant recently installed an SO_2 scrubber and the Tolk and Harrington Plants utilize low sulfur coal to reduce SO_2 emissions. The Colorado Department of Health and Environment along with the Texas Commission on Environmental Quality (TCEQ) made recommendations for unclassified and nonattainment areas to the EPA in September 2015. The EPA's final decision is expected by summer 2016.

If an area is designated nonattainment, the respective states will need to evaluate all SO_2 sources in the area. The state would then submit an implementation plan for the respective areas which would be due in 18 months, designed to achieve the NAAQS within five years. The TCEQ could require additional SO_2 controls on one or more of the units at Tolk and Harrington. It is anticipated the areas near the remaining Xcel Energy power plants would be evaluated in the next designation phase, ending December 2017. Xcel Energy cannot evaluate the impacts of this ruling until the designation of nonattainment areas is made and any required state plans are developed. Xcel Energy believes that, should SO_2 control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

Revisions to the NAAQS for Ozone — In October 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where Xcel Energy operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota and meet the 70 ppb level in the Texas panhandle. In documents issued with the new standard, the EPA projects that both areas will meet the new standard. Current monitored air quality concentrations in areas of Wisconsin, where Xcel Energy operates, are also below the new standard. The Denver Metropolitan Area is currently not meeting the prior ozone standard and will therefore not meet the new, more stringent, standard. If not in attainment, impacted areas would study the sources of nonattainment and make emission reduction plans to attain the new standards. These plans would be due to the EPA in 2020. In conjunction with the CACJA, Xcel Energy has or plans to shut down coal-fired plants in the Denver area, has installed NOx controls on Pawnee and Hayden Unit 1 and will finish installing NOx controls on Hayden Unit 2 in late 2016. The final designation of nonattainment areas will be made in late 2017 based on air quality data years 2014 through 2016. Xcel Energy cannot evaluate the impacts of this ruling in Colorado until the designation of nonattainment areas is made and any required state plan has been developed. Xcel Energy believes that, should NOx control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

NSP-Minnesota NOV — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid-2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also 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. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas production, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with electric production includes certain plants at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. NSP-Minnesota also recognized asbestos obligations for its general office building. AROs also have been recorded for NSP-Minnesota, NSP-Wisconsin, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. NSP-Minnesota and PSCo have also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract.

Xcel Energy has recognized an ARO for the retirement costs of natural gas mains and lines at NSP-Minnesota, NSP-Wisconsin and PSCo and an ARO for the retirement of above ground gas gathering, extraction and wells related to gas storage facilities at PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings.

In April 2015, the EPA published the final rule regulating the management and disposal of coal combustion byproducts (e.g., coal ash) as a nonhazardous waste to the Federal Register. The rule became effective in October 2015. The estimated costs to comply with the final rule were incorporated into the cash flow revisions in 2015.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 14 for further discussion of nuclear obligations.

A reconciliation of Xcel Energy's AROs for the years ended Dec. 31, 2015 and 2014 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2015	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions [(b)]	Ending Balance Dec. 31, 2015
Electric plant						
Nuclear production decommissioning	$ 2,037,947	$ —	$ —	$ 103,077	$ —	$ 2,141,024
Steam and other production ash containment	127,600	—	—	4,746	(759)	131,587
Steam and other production asbestos	69,698	3,875	—	3,670	7,248	84,491
Wind production	38,260	31,085 (a)	—	1,778	523	71,646
Electric distribution	12,593	—	—	463	131	13,187
Other	4,605	127	(273)	178	(94)	4,543
Natural gas plant						
Gas transmission and distribution	149,964	—	—	5,969	—	155,933
Other	3,925	—	—	155	(114)	3,966
Common and other property						
Common general plant asbestos	505	—	—	27	19	551
Common miscellaneous	1,534	—	—	56	44	1,634
Total liability	$ 2,446,631	$ 35,087	$ (273)	$ 120,119	$ 6,998	$ 2,608,562

(a) The liability recognized relates to the NSP-Minnesota Pleasant Valley and Border Wind Farms which were placed in service during 2015.

(b) In 2015, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the asbestos AROs were mainly related to updated cost estimates.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.7 billion as of Dec. 31, 2015, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Accretion	Cash Flow Revisions [(a)]	Ending Balance Dec. 31, 2014 [(b)]
Electric plant					
Nuclear production decommissioning	$ 1,628,298	$ —	$ 86,284	$ 323,365	$ 2,037,947
Steam and other production ash containment	79,353	—	3,354	44,893	127,600
Steam and other production asbestos	50,827	747	2,972	15,152	69,698
Wind production	37,464	—	1,676	(880)	38,260
Electric distribution	12,186	—	444	(37)	12,593
Other	3,551	705	137	212	4,605
Natural gas plant					
Gas transmission and distribution	1,198	20,935	76	127,755	149,964
Other	575	2,865	24	461	3,925
Common and other property					
Common general plant asbestos	480	—	25	—	505
Common miscellaneous	1,458	—	53	23	1,534
Total liability	$ 1,815,390	$ 25,252	$ 95,045	$ 510,944	$ 2,446,631

(a) In 2014, revisions were made to various AROs due to revised estimated cash flows and the timing of those cash flows. Changes to estimated nuclear production decommissioning primarily relate to the triennial filing made to the MPUC in December 2014. See additional information in Note 14. Changes in estimated excavation costs and the timing of future retirement activities resulted in revisions to AROs related to gas transmission and distribution.

(b) There were no ARO liabilities settled during the year ended Dec. 31, 2014.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.7 billion as of Dec. 31, 2014, consisting of external investment funds.

Indeterminate AROs — PSCo has certain underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined. Additionally, outside of the known and recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the amount of asbestos or cost of removal could be determined as of Dec. 31, 2015. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities of its utility subsidiaries that are recovered currently in rates. 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 time periods over which the amounts were accrued and the changing of rates over 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.

The accumulated balances by entity were as follows at Dec. 31:

(Millions of Dollars)	2015	2014
NSP-Minnesota	$ 430	$ 396
PSCo	364	366
SPS	204	68
NSP-Wisconsin	132	123
Total Xcel Energy	$ 1,130	$ 953

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.1 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 $127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $19.9 million for business interruption insurance and $43.7 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

Pacific Northwest FERC Refund Proceeding — A complaint with the FERC posed that sales made in the Pacific Northwest in 2000 and 2001 through bilateral contracts were unjust and unreasonable under the Federal Power Act. The City of Seattle (the City) alleges between $34 million to $50 million in sales with PSCo is subject to refund. In 2003, the FERC terminated the proceeding, although it was later remanded back to the FERC in 2007 by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2015 in the remand proceeding, the FERC issued an order rejecting the City's claim that any of the sales made resulted in an excessive burden and concluded that the City failed to establish a causal link between any contracts and any claimed unlawful market activity. In June 2015, the City requested the FERC grant rehearing of its order, which the FERC denied in December. The City may appeal this order.

Also in December 2015, the Ninth Circuit issued an order and held that the standard of review applied by the FERC to the contracts which the City was challenging is appropriate. The Ninth Circuit dismissed questions concerning whether the FERC properly established the scope of the hearing, and determined that the challenged orders are preliminary and that the Ninth Circuit lacks jurisdiction to review evidentiary decisions until after the FERC's proceedings are final. The City joined the State of California in its request seeking rehearing of this order.

Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately $28 million excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors. First, notwithstanding PSCo's view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the scope of the proceeding established by FERC is being challenged in the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Gas Trading Litigation — e prime, inc. (e prime) is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing, but has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits were commenced against e prime and Xcel Energy (and NSP-Wisconsin, in two instances) between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. The cases were consolidated in U.S. District Court in Nevada. In 2009, five of the cases were settled and one was dismissed. The U.S. District Court in 2011 issued an order dismissing entirely six of the remaining seven lawsuits, and partially dismissing the seventh. Plaintiffs appealed the dismissals to the Ninth Circuit, which reversed the District Court. The matter was ultimately heard by the U.S. Supreme Court in early 2015, which agreed with the Ninth Circuit and remanded the matter to the U.S. District Court. In September 2015, the District Court held a status conference and set deadlines for certain litigation related activities in 2016. A trial date has not yet been set, but is not expected to occur prior to late 2016 or early 2017. Xcel Energy and e prime have concluded that a loss is remote with respect to this matter.

Other Contingencies

Limited Partnership Investment — In October 2015, Energy Impact Fund Investment, LLC (Energy Impact LLC), a wholly-owned non-utility subsidiary of Xcel Energy Inc., entered into a subscription agreement for a limited partnership interest, committing Energy Impact LLC to up to $50 million of total future investments in the newly formed Energy Impact Fund Limited Partnership (Energy Impact Fund LP) over the next five years. Along with the capital contributions of the other limited partners, who are primarily investor-owned utilities or their affiliates, the funding is expected to be used to make private equity investments in entities that are active developers and producers of new and emerging energy technologies applicable to utility operations, products and services. Energy Impact LLC made $0.6 million of capital contributions to the limited partnership in 2015 and uses the equity method to account for its investment.

See Note 12 for further discussion.

14. 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, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately $5 million in 2014 and $10 million in 2013. There were no DOE fuel disposal assessments in 2015. In total, NSP-Minnesota paid approximately $452.1 million to the DOE through Dec. 31, 2015.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 15 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks. Other alternatives for spent fuel storage are being investigated until a DOE facility is available.

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota's 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of $14 million to be recovered in utility customer rates starting in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2015, NSP-Minnesota has accumulated $1.7 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

	Regulatory Basis	
(Thousands of Dollars)	**2015**	**2014**
Estimated decommissioning cost obligation from most recently approved study (in 2014 and 2011 dollars, respectively)	$ 3,012,342	$ 2,694,079
Effect of escalating costs (to 2015 and 2014 dollars, respectively, at 4.36/3.36 percent and 3.63/2.63 percent, respectively)	126,464	289,907
Estimated decommissioning cost obligation (in current dollars)	3,138,806	2,983,986
Effect of escalating costs to payment date (4.36/3.36 percent and 3.63/2.63 percent, respectively)	8,066,688	5,597,302
Estimated future decommissioning costs (undiscounted)	11,205,494	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 3.01 percent and 2.82 percent for 2015 and 2014, respectively)	(6,891,392)	(5,044,470)
Discounted decommissioning cost obligation	$ 4,314,102	$ 3,536,818
Assets held in external decommissioning trust	$ 1,724,150	$ 1,703,921
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,589,952	1,832,897

Calculations and data used by the regulator in approving company rates are useful in assessing future cash flows. The regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2015	2014
Discounted decommissioning cost obligation - regulated basis	$ 4,314,102	$ 3,536,818
Differences in discount rate and market risk premium	(1,275,438)	(1,275,101)
Operating and maintenance costs not included for GAAP	(897,640)	(547,135)
Differences in cost studies (2011 versus 2014, no change in 2015)	—	323,365
Nuclear production decommissioning ARO - GAAP	$ 2,141,024	$ 2,037,947

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Annual decommissioning recorded as depreciation expense: [(a)]	$ 6,862	$ 7,138	$ 6,402

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation.

15. Regulatory Assets and Liabilities

Xcel Energy Inc. and subsidiaries prepare their consolidated financial statements in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the consolidated balance sheets at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations [(a)]	9	Various	$ 90,249	$ 1,368,115	$ 95,054	$ 1,402,360
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	408,994	—	395,329
Net AROs [(b)]	1, 13, 14	Plant lives	—	306,671	—	189,056
Environmental remediation costs	1, 13	Various	6,702	166,883	4,594	149,812
Contract valuation adjustments [(c)]	1, 11	Term of related contract	26,379	128,780	17,730	144,273
Depreciation differences	1	One to sixteen years	14,221	99,835	10,700	104,743
Purchased power contract costs	13	Term of related contract	1,587	70,411	858	69,908
PI EPU	12	Nineteen years	2,967	65,060	8,743	67,379
Conservation programs [(d)]	1	One to five years	31,793	50,047	61,866	58,174
Nuclear refueling outage costs	1	One to two years	67,545	28,913	62,499	19,745
State commission adjustments	1	Plant lives	988	26,708	571	26,092
Losses on reacquired debt	4	Term of related debt	5,008	26,268	5,258	31,276
Renewable resources and environmental initiatives	13	One to two years	33,014	23,565	24,891	29,902
Property tax		One to six years	21,757	14,428	28,024	31,429
Gas pipeline inspection and remediation costs	12	One to four years	6,858	13,662	9,981	21,869
Recoverable purchased natural gas and electric energy costs	1	One to two years	11,783	12,762	68,841	4,745
Other		Various	23,779	47,639	44,448	28,124
Total regulatory assets			$ 344,630	$ 2,858,741	$ 444,058	$ 2,774,216

(a) Includes $257.5 million and $282.4 million for the regulatory recognition of the NSP-Minnesota pension expense of which $21.3 million and $23.8 million is included in the current asset at Dec. 31, 2015 and 2014, respectively. Also included are $12.5 million and $26.1 million of regulatory assets related to the nonqualified pension plan of which $4.0 million and $2.5 million is included in the current asset at Dec. 31, 2015 and 2014, respectively.

(b) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

The components of regulatory liabilities shown on the consolidated balance sheets at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Plant removal costs	1, 13	Plant lives	$ —	$ 1,131,023	$ —	$ 953,660
Investment tax credit deferrals	1, 6	Various	—	48,985	—	52,666
Deferred income tax adjustment	1, 6	Various	—	46,737	—	48,622
Renewable resources and environmental initiatives	12, 13	Various	6,271	41,869	10,427	10,376
PSCo earnings test	12	One to two years	42,868	9,472	57,127	42,819
Gas pipeline inspection costs		Various	1,140	4,273	13,970	642
Gain from asset sales	12	Various	2,640	2,584	2,893	4,472
Deferred electric and steam production and natural gas costs	1	Less than one year	146,235	—	88,527	—
Conservation programs [(a)]	1, 12	Less than one year	34,444	—	103,351	—
Contract valuation adjustments [(b)]	1, 11	Term of related contract	21,661	—	55,751	2,521
DOE settlement	12	One to two years	16,139	—	49,492	—
Low income discount program		Less than one year	2,475	—	3,355	—
Excess depreciation reserve		Less than one year	60	—	10,999	—
Other		Various	32,897	47,946	14,837	47,651
Total regulatory liabilities [(c)]			$ 306,830	$ 1,332,889	$ 410,729	$ 1,163,429

(a) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Revenue subject to refund of $75.0 million and $128.3 million for 2015 and 2014, respectively, is included in other current liabilities.

At Dec. 31, 2015 and 2014, approximately $169 million and $323 million of Xcel Energy's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes recoverable purchased natural gas and electric energy costs and certain expenditures associated with renewable resources and environmental initiatives.

16. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2015 and 2014 were as follows:

	Year Ended Dec. 31, 2015			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (57,628)	$ 110	$ (50,621)	$ (108,139)
Other comprehensive loss before reclassifications	(70)	—	(7,906)	(7,976)
Losses reclassified from net accumulated other comprehensive loss	2,836	—	3,526	6,362
Net current period other comprehensive income (loss)	2,766	—	(4,380)	(1,614)
Accumulated other comprehensive (loss) income at Dec. 31	$ (54,862)	$ 110	$ (55,001)	$ (109,753)

	Year Ended Dec. 31, 2014			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (59,753)	$ 77	$ (46,599)	$ (106,275)
Other comprehensive (loss) income before reclassifications	(163)	33	(7,517)	(7,647)
Losses reclassified from net accumulated other comprehensive loss	2,288	—	3,495	5,783
Net current period other comprehensive income (loss)	2,125	33	(4,022)	(1,864)
Accumulated other comprehensive (loss) income at Dec. 31	$ (57,628)	$ 110	$ (50,621)	$ (108,139)

Reclassifications from accumulated other comprehensive loss for the years ended Dec. 31, 2015 and 2014 were as follows:

	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Thousands of Dollars)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$ 4,515 [(a)]	$ 3,836 [(a)]
Vehicle fuel derivatives	131 [(b)]	(55) [(b)]
Total, pre-tax	4,646	3,781
Tax benefit	(1,810)	(1,493)
Total, net of tax	2,836	2,288
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	6,132 [(c)]	5,998 [(c)]
Prior service (credit) cost	(357) [(c)]	(344) [(c)]
Total, pre-tax	5,775	5,654
Tax benefit	(2,249)	(2,159)
Total, net of tax	3,526	3,495
Total amounts reclassified, net of tax	$ 6,362	$ 5,783

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for details regarding these benefit plans.

17. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes wholesale commodity and 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.

Xcel Energy had equity investments in unconsolidated subsidiaries of $130.0 million and $83.1 million as of Dec. 31, 2015 and 2014, respectively, included in the regulated natural gas utility segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2015					
Operating revenues from external customers	$ 9,275,986	$ 1,672,081	$ 76,419	$ —	$ 11,024,486
Intersegment revenues	1,511	1,251	—	(2,762)	—
Total revenues	$ 9,277,497	$ 1,673,332	$ 76,419	$ (2,762)	$ 11,024,486
Depreciation and amortization	$ 962,565	$ 154,892	$ 7,067	$ —	$ 1,124,524
Interest charges and financing costs	425,999	49,763	93,272	—	569,034
Income tax expense (benefit)	508,568	60,545	(26,394)	—	542,719
Net income	921,403	106,023	(42,941)	—	984,485

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2014					
Operating revenues from external customers	$ 9,465,890	$ 2,142,738	$ 77,507	$ —	$ 11,686,135
Intersegment revenues	1,774	5,893	—	(7,667)	—
Total revenues	$ 9,467,664	$ 2,148,631	$ 77,507	$ (7,667)	$ 11,686,135
Depreciation and amortization	$ 866,746	$ 144,661	$ 7,638	$ —	$ 1,019,045
Interest charges and financing costs	397,824	43,940	86,442	—	528,206
Income tax expense (benefit)	512,551	76,418	(65,154)	—	523,815
Net income (loss)	890,535	128,559	2,212	—	1,021,306

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2013					
Operating revenues from external customers	$ 9,034,045	$ 1,804,679	$ 76,198	$ —	$ 10,914,922
Intersegment revenues	1,332	2,717	—	(4,049)	—
Total revenues	$ 9,035,377	$ 1,807,396	$ 76,198	$ (4,049)	$ 10,914,922
Depreciation and amortization	$ 840,833	$ 128,186	$ 8,844	$ —	$ 977,863
Interest charges and financing costs	386,198	44,927	104,895	—	536,020
Income tax expense (benefit)	495,044	25,543	(36,611)	—	483,976
Net income (loss)	850,572	123,702	(26,040)	—	948,234

18. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Amounts in thousands, except per share data)	March 31, 2015	June 30, 2015	Sept. 30, 2015	Dec. 31, 2015
Operating revenues	$ 2,962,219	$ 2,515,134	$ 2,901,312	$ 2,645,821
Operating income	350,845	422,845	785,812	441,010
Net income	152,066	196,931	426,463	209,025
EPS total — basic	$ 0.30	$ 0.39	$ 0.84	$ 0.41
EPS total — diluted	0.30	0.39	0.84	0.41
Cash dividends declared per common share	0.32	0.32	0.32	0.32

(Amounts in thousands, except per share data)	Quarter Ended March 31, 2014	June 30, 2014	Sept. 30, 2014	Dec. 31, 2014
Operating revenues	$ 3,202,604	$ 2,685,096	$ 2,869,807	$ 2,928,628
Operating income	493,992	397,208	665,680	391,250
Net income	261,221	195,164	368,582	196,339
EPS total — basic	$ 0.52	$ 0.39	$ 0.73	$ 0.39
EPS total — diluted	0.52	0.39	0.73	0.39
Cash dividends declared per common share	0.30	0.30	0.30	0.30

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2015, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control 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, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2015 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 and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Effective January 2016, Xcel Energy implemented the general ledger modules of a new enterprise resource planning ("ERP") system to improve certain financial and related transaction processes. During 2016 and 2017, Xcel Energy will continue implementing additional modules and expects to begin conversion of existing work management system to this same ERP system. In connection with this ongoing implementation, Xcel Energy is updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting procedures. Xcel Energy does not believe that this implementation will have an adverse effect on its internal control over financial reporting.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 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 Over Financial Reporting — For the year ended Dec. 31, 2015.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Balance Sheets — As of Dec. 31, 2015 and 2014.
	Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Capitalization — As of Dec. 31, 2015 and 2014.
2.	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2015, 2014 and 2013.
3.	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
t	Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

Xcel Energy Inc.

1.01*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Barclays Capital Inc. (Exhibit 1.1 to Form 8-K dated March 5, 2013 (file no. 001-03034)).

1.02*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated (Exhibit 1.2 to Form 8-K dated March 5, 2013 (file no. 001-03034)).
1.03*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Morgan Stanley & Co. LLC (Exhibit 1.3 to Form 8-K dated March 5, 2013 (file no. 001-03034)).

PSCo

2.01* t	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers, and PSCo, as Purchaser, dated as of April 2, 2010 (excluding certain schedules and exhibits referred to in the agreement, as amended, which the Registrant agrees to furnish supplemental to the SEC upon request) (Exhibit 2.01 to Form 10-Q for the quarter ended June 30, 2010 (file no. 001-03034)).

Xcel Energy Inc.

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Xcel Energy Inc. Bylaws, as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 17, 2016 (file no. 001-03034)).

Xcel Energy Inc.

4.01*	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. 14, 2000).
4.02*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $300 million principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
4.03*	Supplemental Indenture No. 4 dated March 30, 2007 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $253.979 million aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 2007).
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.05*	Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $400 million principal amount of 7.6 percent Junior Subordinated Notes, Series due 2068 (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.06*	Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.07*	Supplemental Indenture No. 5 dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $550 million principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 10, 2010).
4.08*	Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $250 million principal amount of 4.80 percent Senior Notes, Series due Sept. 15, 2041 (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).
4.09*	Supplemental Indenture No. 7 dated as of May 1, 2013 between Xcel Energy and Wells Fargo Bank, NA, as Trustee, creating $450 million principal amount of 0.75 percent Senior Notes, Series due May 9, 2016 (Exhibit 4.01 to Form 8-K dated May 9, 2013 (file no. 001-03034)).
4.10*	Supplemental Indenture No. 8 dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $250,000,000 aggregate principal amount of 1.20 percent Senior Notes, Series due June 1, 2017 and $250,000,000 aggregate principal amount of 3.30 percent Senior Notes, Series due June 1, 2025. (Exhibit 4.01 to Form 8-K dated June 1, 2015 (file no. 001-03034)).

NSP-Minnesota

4.11*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year ended Dec. 31, 1988 (file no. 001-03034)). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
	Supplemental Trust Indenture dated April 1, 1997, creating $100 million principal amount of 8.5 percent First Mortgage Bonds, Series due Sept. 1, 2019 and $27.9 million principal amount of 8.5 percent First Mortgage Bonds, Series due March 1, 2019 (Exhibit 4.47 to Form 10-K (file no. 001-03034) dated Dec. 31, 1997).

	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
4.12*	Supplemental Trust Indenture dated 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).
4.13*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.14*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture) (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.15*	Supplemental Trust Indenture dated July 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $69 million principal amount of 8.5 percent First Mortgage Bonds, Series due April 1, 2030 (Exhibit 4.06 to NSP-Minnesota Quarterly Report on Form 10-Q (file no. 001-31387) dated Sept. 30, 2002).
4.16*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).
4.17*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated May 18, 2006).
4.18*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
4.19*	Supplemental Trust Indenture dated March 1, 2008 between NSP-Minnesota and The Bank of New York Trust Company, NA, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated March 11, 2008).
4.20*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35 percent First Mortgage Bonds, Series due Nov. 1, 2039 (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated Nov. 16, 2009).
4.21*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.950 percent First Mortgage Bonds, Series due Aug. 15, 2015 and $250 million principal amount of 4.850 percent First Mortgage Bonds, Series due Aug. 15, 2040 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 4, 2010 (file no. 001-31387)).
4.22*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15 percent First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40 percent First Mortgage Bonds, Series due Aug. 15, 2042 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
4.23*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60 percent First Mortgage Bonds, Series due May 15, 2023 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 20, 2013 (file no. 001-31387)).
4.24*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125 percent First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387)).
4.25*	Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300,000,000 principal amount of 2.20 percent First Mortgage Bonds, Series due Aug. 15, 2020 and $300,000,000 principal amount of 4.00 percent First Mortgage Bonds, Series due Aug. 15, 2045 (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Aug. 11, 2015 (file no. 001-31387)).

NSP-Wisconsin

4.26*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust company, providing for the issuance of First Mortgage Bonds (Exhibit 4.01 to Registration Statement 33-39831).
4.27*	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).
4.28*	Supplemental Trust Indenture, dated Dec. 1, 1996, between NSP-Wisconsin and Firstar Trust Company, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).
4.29*	Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firstar Bank, NA as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
4.30*	Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).

4.31* Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375 percent First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).

4.32* Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.700 percent First Mortgage Bonds, Series due Oct. 1, 2042 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Oct. 10, 2012 (file no. 001-03140)).

4.33* Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30 percent First Mortgage Bonds, Series due June 15, 2024. (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated June 23, 2014 (file no. 001-03140)).

PSCo

4.34* Indenture, dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).

4.35* Indentures supplemental to Indenture dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee:

Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)
Jan. 1, 1994	10-K, 1993	4(b)(3)
Sept. 2, 1994	8-K, September 1994	4(b)
Nov. 1, 1996	10-K, 1996 (001-03280)	4(b)(3)
Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)
April 1, 1998	10-Q, March 31,1998 (001-03280)	4(b)
Aug. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.03
Aug. 1, 2005	8-K, Aug. 18, 2005 (001-03280)	4.02

4.36* Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).

4.37* Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129.5 million 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 no. 001-03280).

4.38* Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no. 001-03280) dated Aug. 8, 2007).

4.39* Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80 percent First Mortgage Bonds, Series No. 18 due 2018 and $300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).

4.40* Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).

4.41* Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 8, 2010 (file no. 001-03280)).

4.42* Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041 (Exhibit 4.01 to Form 8-K of PSCo dated Aug. 9, 2011 (file no. 001-03280)).

4.43* Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25 percent First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to PSCo's Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).

4.44* Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50 percent First Mortgage Bonds, Series No. 25 due 2023 and $250 million principal amount of 3.95 percent First Mortgage Bonds, Series No. 26 due 2043 (Exhibit 4.01 to Form 8-K of PSCo dated March 26, 2013 (file no. 001-03280)).

4.45*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30 percent First Mortgage Bonds, Series No. 27 due 2044. (Exhibit 4.01 to Form 8-K of PSCo dated March 10, 2014 (file no. 001-03280)).
4.46*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250,000,000 principal amount of 2.90 percent First Mortgage Bonds, Series No. 28 due 2025. (Exhibit 4.01 to Form 8-K of PSCo dated May 12, 2015 (file no. 001-03280)).

SPS

4.47*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.48*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).
4.49*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).
4.50*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).
4.51*	Fifth Supplemental Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of Series G Senior Notes, 8.75 percent due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789))
4.52*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
4.53*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50 percent First Mortgage Bonds, Series No. 1 due 2041 (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
4.54*	Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and The Bank of New York Mellon Trust Company, N.A., as successor Trustee. (Exhibit 4.03 to SPS' Form 8-K dated June 2, 2014 (file no. 001-03789)).
4.55*	Supplemental Indenture No. 2 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee. (Exhibit 4.06 to SPS' Form 8-K dated June 2, 2014 (file no. 001-03789)).
4.56*	Supplemental Indenture No. 3 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30 percent First Mortgage Bonds, Series No. 3 due 2024. (Exhibit 4.02 to SPS' Form 8-K dated June 9, 2014 (file no. 001-03789)).

Xcel Energy Inc.

10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.04*	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).
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.06*+	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.08*+	Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.09*+	Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2009).
10.10*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).

10.11*+	Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (as amended and restated effective Dec. 15, 2010) (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.12*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.13*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Performance Share Agreement (Exhibit 10.25 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14a*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.26 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14b*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Time-Based Restricted Stock Unit Agreement (Exhibit 10.14b to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2012).
10.15*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed April 5, 2011).
10.16*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.17*+	First Amendment effective Nov. 29, 2011 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.18*+	Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.18 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.19*+	First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.20*+	Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.21*+	First Amendment dated May 21, 2013 to the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.21 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.22*+	Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.22 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.23*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.24*+	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.01 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).
10.25*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2015).
10.26*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. (As First Effective May 20, 2015) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.02 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.27*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.03 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.28+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement.
10.29+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan.

NSP-Minnesota

10.30*	Ownership and Operating Agreement, dated March 11, 1982, between NSP-Minnesota, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3 (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994 (file no. 001-03034)).
10.31*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).

10.32*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.02 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

NSP-Wisconsin

10.33*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.34*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.05 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

PSCo

10.35*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10(c)(1)).
10.36*	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10(c)(2)).
10.37*	Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
10.38*	Settlement Agreement among PSCo and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
10.39*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.03 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

SPS

10.40*	Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).
10.41*	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)).
10.42*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K (file no. 001-03789) May 14, 1979 — Exhibit 5(B)).
10.43*	Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q for the quarter ended Feb. 28, 1982 (file no. 001-03789) — Exhibit 10(b)).
10.44*	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 for the quarter ended Feb. 28, 1982 (file no. 001-03789) — Exhibit 10(c)).
10.45*	Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and SPS.
10.46*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.04 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

Xcel Energy Inc.

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	Powers of Attorney.
31.01	Principal Executive Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2015 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, (ix) Schedule I, and (x) Schedule II.

SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2015	2014	2013
Income			
Equity earnings of subsidiaries	$ 1,045,788	$ 1,077,714	$ 1,018,783
Total income	1,045,788	1,077,714	1,018,783
Expenses and other deductions			
Operating expenses	19,865	19,756	18,513
Other income	(1,242)	(537)	(206)
Interest charges and financing costs	91,801	84,830	102,914
Total expenses and other deductions	110,424	104,049	121,221
Income before income taxes	935,364	973,665	897,562
Income tax benefit	(49,121)	(47,641)	(50,672)
Net income	$ 984,485	$ 1,021,306	$ 948,234
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $(2,777), $(2,528) and $5,897, respectively	$ (4,380)	$ (4,022)	$ 4,714
Derivative instruments, net of tax of $1,764, $1,390 and $2,558, respectively	2,766	2,125	1,488
Other, net of tax of $0, $21 and $117, respectively	—	33	176
Other comprehensive (loss) income	(1,614)	(1,864)	6,378
Comprehensive income	$ 982,871	$ 1,019,442	$ 954,612
Weighted average common shares outstanding:			
Basic	507,768	503,847	496,073
Diluted	508,168	504,117	496,532
Earnings per average common share:			
Basic	$ 1.94	$ 2.03	$ 1.91
Diluted	1.94	2.03	1.91
Cash dividends declared per common share	1.28	1.20	1.11

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating activities			
Net cash provided by operating activities	$ 704,823	$ 842,832	$ 545,177
Investing activities			
Capital contributions to subsidiaries	(820,382)	(422,459)	(535,653)
Investments in the utility money pool	(971,200)	(1,148,000)	(1,778,000)
Return of investments in the utility money pool	987,200	1,204,000	1,706,000
Other, net	(16)	—	—
Net cash used in investing activities	(804,398)	(366,459)	(607,653)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	203,500	(95,500)	297,000
Proceeds from issuance of long-term debt	495,449	—	447,595
Repayment of long-term debt	—	—	(400,000)
Proceeds from issuance of common stock	7,011	180,798	231,767
Dividends paid	(606,574)	(561,411)	(514,042)
Net cash provided by (used in) financing activities	99,386	(476,113)	62,320
Net change in cash and cash equivalents	(189)	260	(156)
Cash and cash equivalents at beginning of period	706	446	602
Cash and cash equivalents at end of period	$ 517	$ 706	$ 446

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in thousands)

	Dec. 31	
	2015	2014
Assets		
Cash and cash equivalents	$ 517	$ 706
Accounts receivable from subsidiaries	315,866	270,921
Other current assets	35,701	47,424
Total current assets	352,084	319,051
Investment in subsidiaries	13,236,758	12,206,575
Other assets	173,136	114,518
Total other assets	13,409,894	12,321,093
Total assets	$ 13,761,978	$ 12,640,144
Liabilities and Equity		
Current portion of long-term debt	$ 450,000	$ —
Dividends payable	162,410	151,720
Short-term debt	584,000	380,500
Other current liabilities	80,526	65,314
Total current liabilities	1,276,936	597,534
Other liabilities	35,694	30,227
Total other liabilities	35,694	30,227
Commitments and contingencies		
Capitalization		
Long-term debt	1,848,428	1,797,901
Common stockholders' equity	10,600,920	10,214,482
Total capitalization	12,449,348	12,012,383
Total liabilities and equity	$ 13,761,978	$ 12,640,144

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and OCI in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Related Party Transactions — Xcel Energy Inc. presents its related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31 were:

	2015		2014	
(Thousands of Dollars)	**Accounts Receivable**	**Accounts Payable**	**Accounts Receivable**	**Accounts Payable**
NSP-Minnesota	$ 58,952	$ —	$ 79,390	$ —
NSP-Wisconsin	17,391	—	20,117	—
PSCo	114,524	—	38,646	—
SPS	21,357	—	28,062	—
Xcel Energy Services Inc.	73,054	—	75,954	—
Xcel Energy Ventures Inc.	20,003	—	20,082	—
Other subsidiaries of Xcel Energy Inc.	10,585	—	8,670	—
	$ 315,866	$ —	$ 270,921	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $784 million, $857 million and $606 million for the years ended Dec. 31, 2015, 2014 and 2013, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The following tables present money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	**Three Months Ended Dec. 31, 2015**
Lending limit	$ 250
Loan outstanding at period end	—
Average loan outstanding	38
Maximum loan outstanding	99
Weighted average interest rate, computed on a daily basis	0.38%
Weighted average interest rate at end of period	N/A
Money pool interest income	$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013
Lending limit	$ 250	$ 250	$ 250
Loan outstanding at period end	—	16	72
Average loan outstanding	27	25	88
Maximum loan outstanding	141	250	243
Weighted average interest rate, computed on a daily basis	0.42%	0.22%	0.30%
Weighted average interest rate at end of period	N/A	0.45	0.25
Money pool interest income	$ 0.1	$ 0.1	$ 0.3

See Xcel Energy’s notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2015, 2014 AND 2013
(amounts in thousands)

	Balance at Jan. 1	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts [a]	Deductions from Reserves [b]	Balance at Dec. 31
Allowance for bad debts:					
2015	$ 57,719	$ 36,074	$ 11,784	$ 53,689	$ 51,888
2014	53,107	42,765	14,067	52,220	57,719
2013	51,394	37,627	14,469	50,383	53,107
NOL and tax credit valuation allowances:					
2015	$ 3,402	$ 2,064	$ 24,784	$ 2,571	$ 27,679
2014	3,263	139	—	—	3,402
2013	3,314	—	—	51	3,263

(a) Recovery of amounts previously written off as related to allowance for bad debts. Accrual of valuation allowance for North Dakota ITC, offset to regulatory liability.

(b) Deductions related to allowance for bad debts relates primarily to write-offs. Reductions to valuation allowances for North Dakota ITC carryforwards primarily due to a consolidated adjustment to the regulatory liability accrual referenced above. Reductions to valuation allowances for NOL carryforwards primarily due to changes in forecasted taxable income.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 19, 2016	By:	/s/ TERESA S. MADDEN
		Teresa S. Madden
		Executive Vice President, Chief Financial Officer
		(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ BEN FOWKE	Chairman, President, Chief Executive Officer and Director
	Ben Fowke	(Principal Executive Officer)
	/s/ TERESA S. MADDEN	Executive Vice President, Chief Financial Officer
	Teresa S. Madden	(Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE	Senior Vice President, Controller
	Jeffrey S. Savage	(Principal Accounting Officer)
*		Director
	Gail Koziara Boudreaux	
*		Director
	Richard K. Davis	
*		Director
	Albert F. Moreno	
*		Director
	Richard T. O’Brien	
*		Director
	Christopher J. Policinski	
*		Director
	James T. Prokopanko	
*		Director
	A. Patricia Sampson	
*		Director
	James J. Sheppard	
*		Director
	David A. Westerlund	
*		Director
	Kim Williams	
*		Director
	Timothy V. Wolf	
*By:	/s/ TERESA S. MADDEN	Attorney-in-Fact
	Teresa S. Madden	