XCEL ENERGY INC
Form 10-K
February 20, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
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. ý Yes o No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes ý No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ý Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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). ý Yes o No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. ý Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes ý No
As of June 30, 2014, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $16,279,552,263 and there were 505,105,562 shares of common stock outstanding.
As of February 16, 2015, there were 505,984,840 shares of common stock outstanding, $2.50 par value.
DOCUMENTS INCORPORATED BY REFERENCE

The Registrant’s Definitive Proxy Statement for its 2015 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)

Cheyenne	Cheyenne Light, Fuel and Power Company
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
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
NMAG	New Mexico Attorney General
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
WDNR	Wisconsin Department of Natural Resources

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Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DRC	Deferred renewable cost rider
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
GAP	Gas affordability program
GCA	Gas cost adjustment
OATT	Open access transmission tariff
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
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
CON	Certificate of need

CP	Coincident peak
CPCN	Certificate of public convenience and necessity
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
FTR	Financial transmission right
FTY	Forecast test year
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
HTY	Historic test year
IFRS	International Financial Reporting Standards
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody’s	Moody’s Investor Services
MVP	Multi-value project
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOx	Nitrogen oxide
NOV	Notice of violation
NSPS	New source performance standard
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

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ROFR	Right of first refusal
RPS	Renewable portfolio standards
RSG	Revenue sufficiency guarantee
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
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
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
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

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COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2014, 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; providing options and solutions to customers; 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 seven percent of its total KWh sold in 2014. 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 2014. 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 subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation, which owns NMC, an inactive company.

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 255,000 customers and natural gas utility service to approximately 111,000 customers. Approximately 98 percent of NSP-Wisconsin’s retail electric operating revenues were derived from operations in Wisconsin during 2014. 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.

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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 2014. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.3 million customers. All of PSCo’s retail electric operating revenues were derived from operations in Colorado during 2014. 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 oil and gas extraction. For small C&I customers, significant electric retail sales include the following industries: real estate and dining establishments. Generally, PSCo’s earnings contribute approximately 45 percent to 55 percent of Xcel Energy’s consolidated net income.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc. and United Water Company, both of which own certain real estate interests; and Green and Clear Lakes Company, which owns water rights and certain real estate interests. PSCo also owns PSRI, which held certain former employees’ life insurance policies. 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 2014. SPS provides electric utility service to approximately 386,000 retail customers in Texas and New Mexico. Approximately 72 percent of SPS’ retail electric operating revenues were derived from operations in Texas during 2014. 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 and crop related agricultural industries. Generally, SPS’ earnings contribute approximately five 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 participate in MISO and SPP competitive bidding processes for transmission projects. XEWT is a transmission-only subsidiary that will 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.

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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. NSP-Minnesota has been granted continued authorization from the FERC 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.
- 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.
- Infrastructure — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes.

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 in CIP. NSP-Minnesota was in compliance with this standard in 2014 and expects to be in compliance in 2015. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

CIP Triennial Plan — In 2012, the DOC approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the savings goals and budgets over the previous plan. The plan sets an electric goal of annually saving the equivalent of 1.5 percent of sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent of sales.

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 2015, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2012	2013	2014	2015 Forecast
NSP System	9,475	9,524	8,848	9,301

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The peak demand for the NSP System typically occurs in the summer. The 2014 uninterrupted system peak demand for the NSP System occurred on July 21, 2014. The 2014 system peak demand was lower due to cooler summer weather. The 2015 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. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. 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 — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

NSP-Minnesota's Filing in Support of e21 Initiative — In December 2014, a collaborative report was issued in Minnesota by a diverse stakeholder group known as the e21 Initiative. The e21 report released a set of recommendations that are intended to act as a blueprint for a new customer-centric, performance-based regulatory approach.

Following the e21 report, NSP-Minnesota filed with the MPUC a plan for supporting the e21 Initiative, which includes the following key objectives:

- Leading the effort to reduce carbon emissions 40 percent by 2030 from 2005 levels;
- Advancing distribution grid modernization;
- Providing our customers with a platform of innovative services and product offerings; and
- Implementing a new regulatory framework that provides both predictable rates for customers and a more timely and nimble review while retaining key benefits of the existing process, thus freeing time for regulatory agencies, stakeholders and utilities to focus on achieving policy objectives.

NSP-Minnesota plans to work with the MPUC and various stakeholders during 2015 to continue the dialogue and implementation of the e21 Initiative and proposals presented by NSP-Minnesota.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Resource Plan with the MPUC, proposing to achieve a 40 percent reduction in carbon emissions by 2030 from 2005 levels through the significant addition of renewables, continued commitment to specific CIP annual achievements, and the continued operation of its existing cost-effective thermal generation. The plan positions NSP-Minnesota to be responsive to future environmental requirements and market trends, builds on the significant investments already made in the NSP System, and acknowledges the divergence in state energy policies within the NSP System. Key points of the resource plan include:

- Adding 600 MW of wind by 2020 and 1,200 MW by 2027, bringing total wind power on the NSP System to over 3,600 MW;
-

Adding 187 MW of large-scale solar energy by 2016 and an additional 1,700 MW of large-scale solar and 500 MW of customer-driven small-scale solar; bringing total solar power on the NSP System to approximately 2,400 MW;
- Operating the Monticello and PI nuclear plants through their current licenses; and
- Continuing to run Sherco Units 1 and 2 with gradually decreasing reliance through 2030.

In February 2015, the MPUC approved the Competitive Acquisition Plan (CAP), in which NSP-Minnesota is required to add capacity to its system to meet a resource need as follows:

- Enter into an agreement for 100 MW of distributed solar with Geronimo Energy LLC;
- Enter into an agreement with Calpine Corporation for a 345 MW expansion at its Mankato Energy Center; and
- Construct a 215 MW Black Dog Unit 6 combustion turbine.

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NSP-Minnesota also proposed use of a collaborative stakeholder process to guide its five-year action plan, and to facilitate the necessary update of its resource analysis to incorporate the CAP outcomes and significantly higher than expected response to its Community Solar Gardens program.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below is $2.0 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total investment. As of Dec. 31, 2014, Xcel Energy has invested $882.3 million of its $1.1 billion share of the five CapX2020 transmission projects.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 KV transmission line
Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2016, although segments are being placed in service as they are completed.

Monticello, Minn. to Fargo, N.D. 345 KV transmission line
In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. In April 2014, the St. Cloud, Minn. to Alexandria, Minn. portion of the project was placed in service. In January 2013, construction started on the project in North Dakota. The final phase of the project, Alexandria, Minn. to Fargo, N.D. is expected to go into service in 2015.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line
In December 2011, MISO granted the final approval of the project as a MVP. Construction started on the project in Minnesota in May 2012. The project is expected to go fully into service in 2015, although segments are being placed in service as they are completed.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line
The Bemidji, Minn. to Grand Rapids, Minn. line was placed in service in September 2012.

Big Stone South to Brookings County, S.D. 345 KV transmission line
In December 2011, MISO granted final approval of the project as a MVP. In March 2014, the SDPUC approved a permit for construction of the project's southern portion. Construction is anticipated to begin in late 2015, with completion 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 less than 20 kilowatts. There are two customer-facing solar programs authorized by the legislature: a community solar garden program that provides bill credits to participating subscribers, and a solar production incentive program for systems equal to or less than 20 kilowatts with authorized payments of $5.0 million per year over five years. NSP-Minnesota launched its Solar*Rewards Community program in December 2014.

The legislation also provides for an alternative tariff based on a distributed solar value or Value of Solar (VOS) methodology. In March 2014, a VOS methodology was approved by the MPUC. However, in September 2014 the MPUC determined that the VOS is not in the public interest for use with community solar gardens. The MPUC instead approved a retail rate based credit ranging from 9.5 to 15 cents per kilowatt hour. The actual bill credit amount is dependent on customer class as well as customers' willingness to transfer the RECs to NSP-Minnesota.

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.

Minneapolis, Minn. Franchise Agreement — In October 2014, the City of Minneapolis and Xcel Energy signed a 10 year franchise agreement. The City of Minneapolis has the option to end the agreement any time after the first five years and the option to extend it to a maximum of 20 years if both parties agree. A separate clean energy partnership agreement with the City of Minneapolis was also signed, which establishes a board comprised of city and utility officials tasked with creating a work plan to promote energy efficiency, the use of renewable energy, and the reduction of carbon emissions.

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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 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. Based on current refueling outage plans, the dates of the required compliance are expected to begin in 2015 with all units expected to be fully compliant by December 2016.

In 2013, the NRC issued a revised order with regard to reliable hardened containment vents. Phase 1 addresses severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate. Phase 2 addresses a second hardened vent off of the dry portion of the containment, or a containment venting strategy that makes it unlikely that a licensee would need to vent from the dry portion of the containment. 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. The majority of these costs are expected to be capital in nature. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and 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. In 2014, the NRC issued a draft of proposed regulatory guidance for risk mitigation of tornado missiles (projectiles impacting the plant). NSP-Minnesota expects the costs associated with compliance with new NRC regulatory guidance for missile protection to be capital in nature and recoverable from customers. NSP-Minnesota is still evaluating the proposed new requirements and has not yet estimated their financial impact.

Nuclear Regulatory Performance — Since 2000, the NRC has had in place a Reactor Oversight Process (ROP) that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5) based on the significance of issues identified in performance indicators or inspection findings. Such 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, 2014, PI Units 1 and 2 were in Column 1 (Licensee Response) with all green performance indicators and no greater than green findings or violations. Monticello was in Column 3 (Degraded Cornerstone) with all green performance indicators and a yellow finding related to flood control. The NRC has completed their inspection that will allow the yellow finding to be closed out. The NRC has notified Monticello that it has a potentially greater than green finding related to plant security which was immediately remedied. Xcel Energy expects to be formally notified of the closeout of the yellow finding, a final determination of the significance of the security finding, and Monticello’s overall column status under the NRC’s ROP in the first half of 2015. Until the NRC makes its determination, we are unable to estimate the cost or impact of any responsive actions required.

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.

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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 also requested that the DOE prepare a supplemental environmental impact statement (EIS) so the NRC Staff can complete its review.

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 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. See Note 13 and Note 14 to the consolidated financial statements for further discussion.

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, 2014, there were 38 casks loaded and stored at the PI plant and 15 canisters loaded and stored at the Monticello plant. An additional 26 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 by the time frames established in the DOE's Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste issued in January 2013.

PFS — The eight partners of PFS, including NSP-Minnesota, have withdrawn their license termination request from the NRC and have stopped activities to dissolve the LLC. This action was taken when the NRC changed its fee rules to no longer require certain licensees like PFS to pay annual fees until their facility becomes operational. PFS is currently reviewing its plans for the future.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed it to prepare an EIS if there are significant impacts or an environmental assessment to support a finding of no significant impact. 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. Issuance of the CSR now allows the NRC to proceed with final license decisions regarding the new and renewal of 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 licensing needs for NSP-Minnesota.

See Notes 13 and 14 to the consolidated financial statements for further discussion regarding nuclear related items.

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Nuclear Plant Power Uprates and Life Extension

PI ISFSI License Renewal — The current license to operate an ISFSI at PI expired in October 2013. An application to renew the ISFSI license for an additional 40 years until 2053 was submitted by NSP-Minnesota to the NRC in October 2011. As PI met the NRC's criteria for timely renewal, it will be allowed to continue to operate under the current license until the NRC has rendered a decision on the license renewal application. The NRC's ASLB will establish a schedule for the hearing which should be completed by the second half of 2015.

Monticello Nuclear Uprate Project — NSP-Minnesota has received all federal and state approvals that are necessary and has completed all of the plant modifications to achieve the 71 MW capacity Monticello Nuclear Uprate Project and is in the process of completing the power ascension testing required by the NRC. Operation at the full increased power level is expected in the first half of 2015. As of Dec. 31, 2014, Monticello was operating at 656 MW, which includes approximately 56 MW of the extended uprate capacity. See Note 12 to the consolidated financial statements for further discussion.

Energy Source Statistics

	Year Ended Dec. 31								
	2014			2013			2012		
NSP System	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	18,079	39	%	15,844	36	%	16,023	35	%
Nuclear	13,434	29		12,161	28		13,231	29	
Natural Gas	3,402	7		5,550	13		6,200	13	
Wind [(a)]	6,243	14		5,481	13		5,443	12	
Hydroelectric	3,560	8		3,223	7		3,193	7	
Other [(b)]	1,417	3		1,323	3		1,617	4	
Total	46,135	100	%	43,582	100	%	45,707	100	%
Owned generation	33,641	73	%	29,249	67	%	31,365	69	%
Purchased generation	12,494	27		14,333	33		14,342	31	
Total	46,135	100	%	43,582	100	%	45,707	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 seven, eight, and six net million KWh for 2014, 2013, and 2012, 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
NSP System Generating Plants	Cost	Percent		Cost	Percent		Cost	Percent		Owned Fuel Cost
2014	$2.23	52	%	$0.89	42	%	$6.27	6	%	$1.94
2013	2.20	49		0.95	40		5.08	11		2.03
2012	2.13	47		0.90	42		4.21	11		1.88

(a) Includes refuse-derived fuel and wood.

The higher cost of natural gas was primarily due to higher market prices from increased demand because of cold weather in early 2014.

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

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Fuel Sources

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2014 and 2013 were approximately 27 and 34 days usage, respectively. At Dec. 31, 2014, coal inventories were below optimal levels due to railcar congestion. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2014 and 2013, coal requirements for the NSP System's major coal-fired generating plants were approximately 9.3 million tons and 7.3 million tons, respectively. Coal requirements for 2014 were higher as Sherco Unit 3 was placed back in service. The estimated coal requirements for 2015 are approximately 8.7 million tons, which reflects the retirement of Black Dog Units 3 and 4.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 88 percent of their estimated coal requirements in 2015, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 100 percent of requirements for the first year, 67 percent of requirements in year two, and 33 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 2015 and 2016. 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 72 percent of the requirements for 2019 through 2027.
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 62 percent of the requirements for 2022 through 2027.
- Current enrichment service contracts cover 100 percent of the requirements through 2021 and approximately 68 percent of the requirements for 2025 through 2027.

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 spot 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, 2014 and 2013, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately

$349 million and $389 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2015 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, 2014, 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 24.2 percent and 22.9 percent of the NSP System's total owned and purchased energy for 2014 and 2013, respectively.

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- Wind energy comprised 13.7 percent and 12.6 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, respectively.
- Hydroelectric energy comprised 7.8 percent and 7.4 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, respectively.
- Biomass and solar power comprised approximately 2.7 percent and 3.0 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, 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 2014, the number of customers utilizing Windsource increased to approximately 43,000 from 37,000 in 2013. Windsource MWh sales increased from approximately 181,000 MWh in 2013 to 186,000 MWh 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 915 PV systems with approximately 11.1 MW of aggregate capacity and over 679 PV systems with approximately 7.3 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2014 and 2013, respectively.

As part of NSP-Minnesota's North Dakota 2013 electric rate case settlement, NSP-Minnesota is required to file a system restack proposal in 2015 to ensure that additional costs for compliance with Minnesota renewable initiatives are not paid for by North Dakota customers.

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Southwestern Minnesota. Currently, the NSP System has more than 100 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 two wind farms which have the capacity to generate 302 MWs. Collectively, the NSP System had approximately 1,860 MWs of wind energy on its system at the end of 2014 and 2013. In October 2013, the MPUC approved four new projects, which are anticipated to provide up to 750 MW of capacity, including two projects totaling 350 MW that will be owned by NSP-Minnesota. One additional 20 MW project was approved in 2014. All five projects are targeted to be operational in late 2015. With the new projects, the NSP System is anticipated to have approximately 2,630 MWs of wind power. 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 $41 for 2014 and 2013. 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 2014 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2014, with certain projects qualifying into future years.

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 268 MW of capacity. For 2014, PPAs provided approximately 38 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 850 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy-related products. See Item 7 for further discussion.

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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 CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the Hampton, Minn. to La Crosse, Wis. project in May 2012. The Wisconsin route is approximately 50 miles of new transmission line with an estimated cost of $211 million. The line is expected to go into service in the fall of 2015.

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 CPCN for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. The proposed line, known as the Badger Coulee line, would run between 154 and 187 miles based on the permitted route, which includes an estimated project cost, including AFUDC, of between $540 and $580 million. NSP-Wisconsin's half of the project is shared with two partners, Dairyland Power Cooperative and WPPI Energy. NSP-Wisconsin's portion of the investment is estimated to be between $190 and $207 million. In 2011, MISO determined the line to be a MVP project, and as such, eligible for cost sharing under MISO's MVP tariff. The PSCW held hearings on the application in January 2015, and a decision is expected by April 2015. If approved, NSP-Wisconsin and ATC anticipate beginning construction on the line in late 2016, with completion by late 2018.

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Fuel Supply and Costs

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

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 annually in January, as well as on an interim basis.
- 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 — As part of its pending electric rate case, PSCo proposed to establish a CACJA rider, retroactive to Jan. 1, 2015, to recover 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 2015.

Capacity and Demand

Uninterrupted system peak demand for PSCo’s electric utility for each of the last three years and the forecast for 2015, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2012	2013	2014	2015 Forecast
PSCo	6,689	6,678	6,152	6,475

The peak demand for PSCo's system typically occurs in the summer. The 2014 uninterrupted system peak demand for PSCo occurred on July 7, 2014. The 2014 system peak demand was lower due to reduced wholesale loads and cooler summer weather. In 2013 Comanche Unit 3 was off-line, which increased PSCo's system load by approximately 250 MW for the backup power provided by PSCo to the joint owners. The forecast of 2015 system peak assumes normal weather conditions.

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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 — In 2013, PSCo issued an All-Source RFP for 250 MW of generation by the end of 2018. PSCo also issued a separate wind RFP for PPAs only.

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, which are expected to be operational in 2015. These additional PPAs will bring the installed wind capacity on PSCo's system in Colorado to 2,650 MW;
- The addition of 170 MW of utility-scale solar generation PPAs, which are expected to be operational in 2016. PSCo has approximately 80 MW of utility-scale solar and approximately 188 MW of customer-sited solar generation;
- The addition of 317 MW of natural gas fired generation PPAs, which will 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 construction of a new natural gas fired combined cycle unit at Cherokee generating station and the addition of emissions controls at the Pawnee and Hayden stations. PSCo also expects to retire the Cherokee Unit 3 and Valmont Unit 5 coal-fired power plants by the end of 2015 and 2017, respectively.

Brush, Colo. to Castle Pines, Colo. 345 KV Transmission Line — In March 2014, PSCo filed with the CPUC for a CPCN to construct a new 345 KV transmission line originating from Pawnee Station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. The estimated cost of the project is $178 million. In September 2014, PSCo entered into a partial settlement agreement with the CPUC Staff supporting the grant of a CPCN for the line. The OCC has opposed the CPCN. In November 2014, the ALJ issued a recommended decision approving the CPCN, but delaying construction until May 2020. PSCo filed exceptions to the recommended decision, requesting clarification and reconsideration to commence certain portions of the project in 2015. A CPUC decision is anticipated in the first quarter of 2015.

Thornton, Colo. Substation Project — In October 2014, PSCo filed with the CPUC for a CPCN to construct a new substation to serve growing load in and around Thornton, Colo. to be placed into service in July 2016. The estimated cost of the project is approximately $34 million. The OCC and the City of Thornton have intervened in the CPCN proceeding. In November 2014, the matter was referred to an ALJ for hearing procedures. In January 2015, PSCo and the OCC filed a settlement agreement with the CPUC requesting approval of the CPCN. The City of Thornton did not oppose the settlement. An evidentiary hearing was held in February 2015 and a CPUC decision is anticipated in the first quarter of 2015.

Boulder, Colo. Municipalization — PSCo’s franchise agreement with the City of Boulder (Boulder) expired in December 2010. 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 Boulder City Council passed an ordinance to establish an electric utility.

In 2013, the CPUC ruled that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder’s city limits, and will determine certain system separation matters as well as what facilities need to be constructed to ensure reliable service. The CPUC has declared that it should make its determinations prior to any eminent domain actions. In January 2014, Boulder appealed this ruling to the Boulder District Court. In January 2015, the Boulder District Court affirmed the CPUC decision.

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Boulder sent PSCo an offer of $128 million for certain portions of PSCo's transmission and distribution business. PSCo has notified Boulder that its offer was deficient. Under Colorado law, a condemning entity must pay the owner fair market value for the taking of and damages to the remainder of the property.

In July 2014, Boulder filed a petition for condemnation in the Boulder District Court. PSCo filed a motion to dismiss the petition based upon the CPUC's ruling that it must determine the appropriate system separations prior to Boulder filing its condemnation case. PSCo's motion to dismiss was granted in February 2015. This decision does not prevent Boulder from filing another condemnation petition if it obtains CPUC approval of a separation plan.

In August 2014, PSCo filed a petition with the FERC requesting an order requiring that Boulder's attempt to acquire PSCo's transmission and distribution facilities by condemnation requires prior FERC approval under the Federal Power Act. In December 2014, the FERC issued an order granting PSCo's petition.

If Boulder proceeds with another condemnation petition and were to succeed in the eminent domain proceeding, PSCo would seek to obtain full compensation for the business and its associated property taken by Boulder, as well as for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

RES Compliance Plan — Colorado law mandates that at least 30 percent of PSCo's energy sales are supplied by renewable energy by 2020 and includes a distributed generation standard. In July 2013, PSCo filed its 2014 RES compliance plan. In July 2014, the ALJ issued a recommended decision accepting PSCo's compliance plan with modifications. The CPUC approved the recommended decision with modifications in December 2014. PSCo subsequently requested additional adjustments to the CPUC's decision, which were granted through an order issued in February 2015.

Net Metering Standard — In a filing, PSCo proposed to track and quantify the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive," for purposes of equitably recovering costs between customers. The CPUC assigned the net metering issue to its own docket. A CPUC decision is anticipated in the third quarter of 2015.

Steam System Package Boilers and Regulatory Plan — In December 2014, PSCo filed the results of a steam survey along with both a short-term plan and a long-term plan for the steam system consisting of a request for a conditional CPCN to construct either one or two boilers for its steam utility, dependent on the next two seasons of winter peaking capacity. A decision is anticipated in the third quarter of 2015.

Energy Source Statistics

	Year Ended Dec. 31								
	2014			2013			2012		
PSCo	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	18,274	53	%	19,647	56	%	21,367	59	%
Natural Gas	8,601	25		7,565	22		7,930	22	
Wind [(a)]	6,472	19		6,750	19		5,752	16	
Hydroelectric	617	2		655	2		590	2	
Other [(b)]	294	1		250	1		263	1	
Total	34,258	100	%	34,867	100	%	35,902	100	%
Owned generation	23,023	67	%	22,873	66	%	23,766	66	%
Purchased generation	11,235	33		11,994	34		12,136	34	

Total	34,258	100	%	34,867	100	%	35,902	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 197, 172, and 133 net million KWh for 2014, 2013, and 2012, respectively.

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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
PSCo Generating Plants	Cost	Percent	Cost	Percent	Average Owned Fuel Cost
2014	$1.82	75 %	$5.32	25 %	$2.68
2013	1.84	80	4.86	20	2.45
2012	1.77	78	4.25	22	2.31

The higher cost of natural gas was primarily due to higher market prices from increased demand because of cold weather in early 2014.

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, 2014 and 2013 were approximately 36 and 41 days usage, respectively. At Dec. 31, 2014, coal inventories were below optimal levels due to railcar congestion. PSCo’s generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2014 and 2013, PSCo’s coal requirements for existing plants were approximately 10.3 million tons and 11.3 million tons, respectively. The estimated coal requirements for 2015 are approximately 11.0 million tons.

PSCo has contracted for coal supply to provide 96 percent of its estimated coal requirements in 2015, and a declining percentage of requirements in subsequent years. PSCo’s general coal purchasing objective is to contract for approximately 100 percent of requirements for the first year, 67 percent of requirements in year two, and 33 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 of its coal requirements in 2015 and 2016. 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.

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At Dec. 31, 2014, PSCo’s commitments related to gas supply contracts, which expire in various years from 2015 through 2023, were approximately $902 million and commitments related to gas transportation and storage contracts, which expire in various years from 2015 through 2060, were approximately $685 million.

- At Dec. 31, 2013, PSCo’s commitments related to gas supply contracts were approximately $1.1 billion and commitments related to gas transportation and storage contracts were approximately $723 million.

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

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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, 2014, PSCo was in compliance with mandated RPS, which require generation from renewable resources of 12 percent of electric retail sales.

- Renewable energy comprised 21.4 percent and 21.9 percent of PSCo's total owned and purchased energy for 2014 and 2013, respectively.
- Wind energy comprised 18.9 percent and 19.3 percent of PSCo's total owned and purchased energy for 2014 and 2013, respectively.
- Hydroelectric, biomass and solar power comprised approximately 2.5 percent and 2.6 percent of PSCo's total owned and purchased energy for 2014 and 2013.

PSCo also offers customer-focused renewable energy initiatives. Windsource allows customers to purchase a portion or all of their electricity from renewable sources. In 2014, the number of customers utilizing Windsource increased to approximately 41,000 from 37,000 in 2013. Windsource MWh sales declined slightly, due in part to loss of certain commercial customers, from approximately 197,000 MWh in 2013 to 188,000 MWh 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 24,000 PV systems with approximately 221 MW of aggregate capacity and over 18,250 PV systems with approximately 188 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2014 and 2013, respectively. In 2014, the first community solar gardens were interconnected in Colorado. As of Dec. 31, 2014, 14 gardens have been completed with 9.6 MW of capacity.

Wind — PSCo acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Colorado. Currently, PSCo has 18 of these agreements in place, with facilities ranging in size from two MW to over 300 MW. PSCo owns and operates the 26 MW Ponnequin Wind Farm in northern Colorado, which has been in service since 1999.

- PSCo had approximately 2,340 MW and 2,170 MW of wind energy on its system at the end of 2014 and 2013, respectively.
- In October 2013, the CPUC approved the addition of 450 MW of Colorado wind generation PPA's.
- With the new projects, PSCo is anticipated to have approximately 2,592 MW of wind power by 2016. 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 $45 in both 2014 and 2013. 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 2014 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2014, with certain projects qualifying into future years.

Wholesale Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. 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. SPS has received authorization from the FERC to make wholesale electric sales at market-based prices.

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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 distribution costs in Texas.
- DRC — The DRC rider previously recovered deferred costs associated with renewable energy programs in New Mexico.
- 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.
- RPS — The RPS rider recovers deferred costs associated with renewable energy programs in New Mexico.
- TCRF — The TCRF rider recovers transmission infrastructure improvement costs and changes in wholesale transmission charges in Texas.

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.

NMPRC regulations require SPS to request authority to continue collecting its fuel and purchased power costs through a fuel adjustment clause every four years. The NMPRC previously granted SPS authority to use a fuel adjustment clause through November 2014, and allows its continued use while a new application is pending. In November 2014, SPS filed an application with the NMPRC to continue use of the fuel adjustment clause for an additional four years. Hearings are scheduled for May 2015.

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 2015, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2012	2013	2014	2015 Forecast
SPS	5,265	5,056	4,871	4,982

The peak demand for the SPS system typically occurs in the summer. The 2014 uninterrupted system peak demand for SPS occurred on Aug. 7, 2014. The 2014 peak demand decreased due to cooler summer 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 net dependable 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.

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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, which are retail and wholesale load obligations with terms of more than one year.

SPP Integrated Market (IM) — In February 2014, the FERC granted SPS approval to make sales to the SPP IM at market-based rates. Further, In February and March, respectively, SPS was granted interim approval for revised QF tariff pricing in Texas and New Mexico to be consistent with the new market and to coincide with the start of the IM. The SPP IM began operations in March 2014 and operates in the day ahead and real time energy and ancillary services market. In April 2014, the FERC approved SPS' filings to modify its wholesale power sales contracts to allow recovery of SPP IM charges and revenues through the SPP wholesale FCA.

SPS Transmission NTCs — As a member of SPP, SPS accepts NTCs for electric transmission line and substation projects to be built within the SPP footprint. SPS has accepted NTCs for projects with an estimated capital cost of approximately $1.9 billion and will continue to review new NTCs for acceptance as they are issued. These projects generally span several years to plan, site, procure and develop. The NMPRC and the PUCT must approve the siting and routing of any SPP identified transmission line NTC projects that require permitting approval. Projects identified through SPP NTCs may have costs allocated to other SPP members in accordance with the SPP OATT. Costs allocated to SPS are permissible for recovery through the NMPRC, the PUCT and the FERC processes.

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. SPS is developing plans for these projects in preparation of submitting CCNs to the PUCT and the NMPRC. These projects are intended to provide regional reliability benefits as well as the ability to serve the increase in load in southeastern New Mexico.

TUCO substation to Woodward, Okla. 345 KV transmission line

The TUCO to Woodward District extra high voltage interchange is a 345 KV transmission line. SPS constructed the line to just inside the Oklahoma state line, and Oklahoma Gas and Electric Company (OGE) built from there to Woodward, Okla. SPS' investment in the TUCO to Woodward line and substation is approximately $206 million and is expected to be recovered from SPP members, including SPS, in accordance with the SPP tariff. The line was placed into service in September 2014.

Hitchland substation to Woodward, Okla. 345 KV transmission line

The Hitchland substation to Woodward, Okla. line is a 345 KV double circuit transmission line and associated substation facilities in the Oklahoma and Texas Panhandle. SPS built the first 30 miles to Beaver County, Okla. and OGE completed the line from there to Woodward, Okla. SPS' investment for the Hitchland to Woodward line and substation is approximately $58 million and is expected to be recovered from SPP members in accordance with the SPP tariff. The line was placed into service in May 2014.

Potash Junction substation to Roadrunner substation 345 KV transmission line

In April 2014, SPS filed a CCN with the NMPRC for a new 345 KV transmission line from the Potash Junction substation to the Roadrunner substation, both near Carlsbad, N.M. The proposed line would run 40 miles and cost an estimated $54 million. The NMPRC approved the CCN in December 2014. The line is anticipated to be placed into service in the fourth quarter of 2015.

SPS Resource Plans — SPS is required to develop and implement a renewable portfolio plan in which 15 percent of its energy to serve its New Mexico retail customers is produced by renewable resources in 2015. SPS primarily fulfills its renewable portfolio requirements through PPAs.

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Energy Source Statistics

	Year Ended Dec. 31					
	2014		2013		2012	
SPS	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	12,770	48 %	14,184	49 %	14,005	49 %
Natural Gas	10,068	37	11,235	38	12,088	43
Wind [(a)]	3,762	14	3,507	12	2,103	7
Other [(b)]	180	1	167	1	177	1
Total	26,780	100 %	29,093	100 %	28,373	100 %
Owned generation	16,956	63 %	18,814	65 %	19,940	70 %
Purchased generation	9,824	37	10,279	35	8,433	30
Total	26,780	100 %	29,093	100 %	28,373	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 10, 11, and eight net million KWh for 2014, 2013, and 2012, 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
SPS Generating Plants	Cost	Percent	Cost	Percent	Owned Fuel Cost
2014	$2.07	71 %	$4.76	29 %	$2.85
2013	2.14	71	3.97	29	2.68
2012	1.87	67	2.99	33	2.24

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 2016 for Harrington and Tolk. SPS normally maintains approximately 43 days of coal inventory. As of Dec. 31, 2014 and 2013, coal inventories at SPS were approximately 17 and 42 days supply, respectively. At Dec. 31, 2014, coal inventories were below optimal levels due to railcar congestion. TUCO has coal agreements to supply 87 percent of SPS' estimated coal requirements in 2015, and a declining percentage of the requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 100 percent of requirements for the first year, 67 percent of requirements in year two, and 33 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 2015 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 $3 million and $21 million and commitments related to gas transportation and storage contracts were approximately $222 million and $201 million at Dec. 31, 2014 and 2013, respectively.

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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, 2014, SPS is in compliance with mandated RPS, which require generation from renewable resources of approximately four percent and 10 percent of Texas and New Mexico electric retail sales, respectively.

- Renewable energy comprised 14.7 percent and 12.7 percent of SPS' energy for 2014 and 2013, respectively.
- Wind energy comprised 14.0 percent and 12.1 percent of SPS' energy for 2014 and 2013, respectively.
- Solar power comprised approximately 0.4 percent of SPS' energy for both 2014 and 2013.

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 Windsource participants remained consistent at approximately 900 in 2013 and 2014. Windsource sales were approximately 4,400 MWh in 2013 and 3,900 MWh 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 315 PV systems with approximately 20.8 MW of aggregate capacity and over 115 PV systems with approximately 7.6 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2014 and 2013, respectively.

Wind — SPS acquires its wind energy from independent power producers (IPP) and qualified facilities (QF) contracts 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 1,500 MW and 1,000 MW of wind energy on its system at the end of 2014 and 2013, 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 contracts was approximately $26 for both 2014 and 2013. 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 2014 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2014, with certain projects qualifying into future years.

Wholesale Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge 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 October 2014, the FERC upheld the determination of the long-term growth rate to be used in its new ROE methodology. Several parties sought rehearing of the June 2014 order and therefore the new FERC policy may be subject to additional changes.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In 2011, the FERC issued a final ruling, Order 1000, adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. Order 1000 requires:

- The development of tariffs that provide for joint regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region;

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- The coordination between regions for the development of interregional plans for transmission planning and cost allocation;
- Each public utility transmission provider to amend its Open Access Transmission Tariff to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; and
- The removal of ROFR provisions from FERC-jurisdictional wholesale transmission contracts and tariffs that presently grant the incumbent transmission owner a federal ROFR to build certain types of transmission projects in its service area.

MISO, SPP and the jurisdictional WestConnect utilities, including PSCo, have submitted multiple compliance filings with the FERC to implement the Order 1000 requirements. Some of the new compliance provisions that were filed have already been approved but others remain under review by the FERC.

In August 2014, the D.C. Circuit denied all appeals and upheld Order 1000 in its entirety and indicated that challenges to the removal of federal ROFR provisions from individual contracts or tariffs could be considered in individual compliance filings. The FERC's decisions to remove federal ROFR provisions in certain MISO and SPP agreements were appealed to federal courts of appeal in 2014, and those appeals are pending. The removal of a federal ROFR would eliminate rights that NSP-Minnesota, NSP-Wisconsin and SPS currently have under the MISO and SPP tariffs, respectively, to build certain transmission projects within their footprints.

In 2014, MISO and SPP both filed compliance plans that would allow the RTOs to recognize state law ROFRs in any selection process for Order 1000 transmission projects. The commissions granted these requests in 2014. In 2015, the FERC issued orders on rehearing on the compliance filing that would continue to allow MISO and SPP the authority to recognize state ROFRs. Xcel Energy has state ROFRs in Minnesota, North Dakota, South Dakota and believes it has a state ROFR in Texas.

Order 1000 could create opportunities for third parties to build and own certain regional transmission projects that had previously been reserved for the MISO and SPP transmission owners, potentially reducing NSP-Minnesota's, NSP-Wisconsin's and SPS's financial return on new investments in electric transmission facilities. Xcel Energy formed its TransCo entities to pursue opportunities for new investments in electric transmission facilities that may be possible under Order 1000. The ultimate impact of Order 1000 on future Xcel Energy transmission investment is not known at this time.

TransCos — In 2014, Xcel Energy formed the Xcel Energy Transmission Holding Company, LLC and two of its TransCo subsidiaries that will participate in the MISO and SPP competitive bidding processes. Transmission assets held by these entities will be subject to FERC jurisdiction. Xcel Energy has also formed an additional TransCo subsidiary to pursue transmission projects in the western United States.

MISO
XETD was approved as a non-transmission owning member in MISO in April 2014, and a qualified transmission developer (QTD) in December 2014. This allows XETD to competitively bid for MISO transmission projects starting in 2015 or 2016.

SPP
In September 2014, SPP determined that XEST's participant application was complete. This allows XEST to competitively bid for SPP transmission projects starting in 2015. The number of projects made available for competitive bidding in SPP in 2015, as the RTO establishes its rules and processes, is not expected to be significant.

In November 2014, the FERC approved XETD and XEST’s forward-looking transmission formula rates that will apply in their respective jurisdictions with an effective date retroactive to Nov. 1, 2014. The FERC approved the following items requested in the TransCo rate filings:

- A capital structure based on 55 percent equity and 45 percent debt for both TransCos;
- Deferral of start-up costs for future recovery in rates, subject to a future filing prior to actual recovery;
- XETD’s request for a base ROE using the currently applicable MISO regional rate of 12.38 percent, subject to any potential modifications resulting from a pending ROE complaint against the MISO transmission owners; and
- XEST’s base ROE of 10.64 percent. However, the FERC suspended the proposed ROE and the ROE will be subject to refund and potential modifications resulting from settlement judge or hearing procedures set for 2015. Also, the FERC granted XEST’s request for a 50 basis point adder for membership in SPP.

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In January 2015, XETD and XEST submitted compliance filings to the orders. Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a protest to the XEST compliance filing in February 2015. The first settlement conference for the XEST ROE issue was held Jan. 6, 2015. The next settlement conference is scheduled for March 10, 2015.

WestConnect
XEWT executed the WestConnect planning participation agreement in January 2015, and is participating in the WestConnect regional planning process as an independent transmission developer or owner.

NERC Critical Infrastructure Protection Requirements — The FERC has approved version 5 of NERC's critical infrastructure protection standards. Requirements must be applied 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 evaluating the new requirements and identifying initiatives needed to meet the compliance deadlines.

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 will become enforceable in October 2015 with staggered milestone deliverable dates through 2016. Xcel Energy is currently in the process of developing and performing the initial risk assessment in accordance with the requirements of the standard, which will provide a basis to estimate the cost of protections necessary to meet 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 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 over SPP transmission facilities between the traditional MISO region in the Midwest and the Entergy system. Several cases have been filed with the FERC by MISO and SPP. In June 2014, the FERC accepted a proposed tariff change by MISO to recover transmission charges imposed by SPP retroactive to January 2014, and set the issues for settlement judge and hearing procedures. If SPP is successful in charging MISO for use of the SPP system, the NSP System would experience higher costs from MISO, which could be material, but SPS would collect revenues from SPP. The outcome of the JOA disputes, and the potential impact on Xcel Energy, are uncertain at this time.

Xcel Energy Services Inc. and NSP-Wisconsin vs. ATC (La Crosse, Wis. to Madison, Wis. Transmission Line) — In February 2012, Xcel Energy Services Inc. and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. In July 2012, the FERC ruled favorably on Xcel Energy Services Inc.'s and NSP-Wisconsin's complaint, ruling that the responsibilities to construct the La Crosse, Wis. to Madison, Wis. transmission line, also known as the Badger Coulee line, belong equally to NSP-Wisconsin and ATC. In August 2012, ATC requested rehearing and requested that the FERC grant a stay of the ruling. ATC and NSP-Wisconsin jointly filed a CPCN application with the PSCW for the project in October 2013. In May 2014, the FERC issued an order denying the ATC request for rehearing and motion for stay. The 60 day period for ATC to appeal the FERC order lapsed, making the FERC ruling final.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments depending on whether the project is primarily local or regional in nature. If a project qualifies as a MVP, the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 KV and higher) projects expected to serve multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving.

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Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2014	2013	2012
Electric sales (Millions of KWh)			
Residential	24,857	25,306	25,033
Large C&I	27,657	27,206	27,396
Small C&I	36,022	35,873	35,660
Public authorities and other	1,104	1,098	1,109
Total retail	89,640	89,483	89,198
Sales for resale	14,931	15,065	15,781
Total energy sold	104,571	104,548	104,979
Number of customers at end of period			
Residential	2,994,075	2,965,717	2,940,024
Large C&I	1,128	1,132	1,147
Small C&I	426,289	422,553	419,618
Public authorities and other	68,306	67,998	68,510
Total retail	3,489,798	3,457,400	3,429,299
Wholesale	44	65	75
Total customers	3,489,842	3,457,465	3,429,374
Electric revenues (Thousands of Dollars)			
Residential	$2,956,576	$2,906,208	$2,713,575
Large C&I	1,789,742	1,694,720	1,534,728
Small C&I	3,382,750	3,248,586	3,023,154
Public authorities and other	143,442	138,126	130,538
Total retail	8,272,510	7,987,640	7,401,995
Wholesale	796,766	693,728	687,912
Other electric revenues	396,614	352,677	427,389
Total electric revenues	$9,465,890	$9,034,045	$8,517,296
KWh sales per retail customer	25,686	25,882	26,011
Revenue per retail customer	$2,370	$2,310	$2,158
Residential revenue per KWh	11.89 ¢	11.48 ¢	10.84 ¢
Large C&I revenue per KWh	6.47	6.23	5.60
Small C&I revenue per KWh	9.39	9.06	8.48
Total retail revenue per KWh	9.23	8.93	8.30
Wholesale revenue per KWh	5.34	4.60	4.36

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Energy Source Statistics

	Year Ended Dec. 31								
	2014			2013			2012		
Xcel Energy	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	49,123	46	%	49,675	46	%	51,395	47	%
Natural Gas	22,071	21		24,350	23		26,218	24	
Wind [(a)]	16,478	15		15,738	14		13,298	12	
Nuclear	13,503	12		12,177	11		13,249	12	
Hydroelectric	4,203	4		3,900	4		3,800	3	
Other [(b)]	1,795	2		1,704	2		2,022	2	
Total	107,173	100	%	107,544	100	%	109,982	100	%
Owned generation	73,620	69	%	70,936	66	%	75,071	68	%
Purchased generation	33,553	31		36,608	34		34,911	32	
Total	107,173	100	%	107,544	100	%	109,982	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 222, 198, and 152 net million KWh for 2014, 2013 and 2012, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of the utility subsidiaries are continued volatility in natural gas market prices, 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 2014, average annual sales to the typical residential customer declined 14 percent, while sales to the typical small C&I customer declined 6 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.

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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 752,931 MMBtu, which occurred on Jan. 2, 2014 and 767,636 MMBtu, which occurred on Jan. 21, 2013.

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 610,048 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 246,000 MMBtu of natural gas per day, or approximately 30 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 August 2014, the MPUC approved NSP-Minnesota’s contract demand levels for the years 2007 through 2013. Demand levels filed with the MPUC in 2014 are awaiting approval.

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.

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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:

2014	$6.17
2013	4.53
2012	4.41

The higher cost of natural gas was primarily due to higher at market prices from increased demand because of cold weather in early 2014.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2015 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, 2014, NSP-Minnesota was committed to approximately $294 million in such obligations under these contracts.

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

See 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 163,520 MMBtu, which occurred on Jan. 6, 2014, and 155,087 MMBtu, which occurred on Jan. 21, 2013.

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 131,857 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 13 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

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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 2014-2015 supply plan was approved by the PSCW in October 2014.

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:

2014	$6.52
2013	4.51
2012	4.36

The higher cost of natural gas was primarily due to higher at market prices from increased demand because of cold weather in early 2014.

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 2015 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, 2014, NSP-Wisconsin was committed to approximately $71 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 8 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 2015.

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 2015.

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Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation to be 1,983,672 MMBtu. In addition, firm transportation customers hold 771,112 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,754,784 MMBtu per day. The maximum daily deliveries for PSCo for firm and interruptible services were 2,116,747 MMBtu on Dec. 30, 2014 and 1,865,207 MMBtu on Dec. 5, 2013.

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 1,814,265 MMBtu per day, which includes 850,840 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide approximately 41,000 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo’s city gate meter stations.

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:

2014	$4.91
2013	4.20
2012	4.28

The higher cost of natural gas was primarily due to higher at market prices from increased demand because of cold weather in early 2014.

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, 2014, PSCo was committed to approximately $1.4 billion in such obligations under these contracts, which expire in various years from 2015 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 2014, PSCo purchased natural gas from approximately 34 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.

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Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2014	2013	2012
Natural gas deliveries (Thousands of MMBtu)			
Residential	152,269	150,280	123,835
C&I	95,879	92,849	77,848
Total retail	248,148	243,129	201,683
Transportation and other	124,000	125,057	116,611
Total deliveries	372,148	368,186	318,294
Number of customers at end of period			
Residential	1,795,190	1,776,849	1,760,364
C&I	155,515	154,646	154,158
Total retail	1,950,705	1,931,495	1,914,522
Transportation and other	6,594	6,320	5,789
Total customers	1,957,299	1,937,815	1,920,311
Natural gas revenues (Thousands of Dollars)			
Residential	$1,320,207	$1,126,859	$964,642
C&I	727,071	586,548	488,644
Total retail	2,047,278	1,713,407	1,453,286
Transportation and other	95,460	91,272	84,088
Total natural gas revenues	$2,142,738	$1,804,679	$1,537,374
MMBtu sales per retail customer	127.21	125.88	105.34
Revenue per retail customer	$1,050	$887	$759
Residential revenue per MMBtu	8.67	7.50	7.79
C&I revenue per MMBtu	7.58	6.32	6.28
Transportation and other revenue per MMBtu	0.77	0.73	0.72

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 on-site solar generation (typically rooftop solar) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Finally, in some of our states, customers can elect to subscribe to a community solar garden at pricing that affords them the same opportunity to avoid fixed charges as if they had rooftop installations.

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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. 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. 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 future environmental regulations under consideration 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 57.6 million and 57.2 million tons of CO_2 in 2014 and 2013, 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 11.4 million and 14.7 million tons of CO_2 in 2014 and 2013, respectively. Estimated total CO_2 emissions associated with service to Xcel Energy electric customers decreased by 3.0 million tons in 2014 compared to 2013. The decrease in emissions was associated with a decrease of 5.4 million net MWh of generation since 2011. The average annual decrease in CO_2 emissions since 2011 is approximately 3.1 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, 2014, Xcel Energy had 11,589 full-time employees and 102 part-time employees, of which 5,588 were covered under collective-bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

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EXECUTIVE OFFICERS

Ben Fowke, 56, 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; Executive Vice President and Chief Financial Officer, Xcel Energy Inc., December 2008 to August 2009.

Christopher B. Clark, 48, 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 Attorney and Director, Government and Regulatory Affairs, NSP-Minnesota, November 2007 to October 2012.

David L. Eves, 56, President and Director, PSCo, January 2015 to present. Previously, President, Director and Chief Executive Officer, PSCo, December 2009 to December 2014; President, Director and Chief Operating Officer, PSCo, November 2009 to December 2009; President and Director, SPS, December 2006 to November 2009; Chief Executive Officer, SPS, August 2006 to November 2009.

David T. Hudson, 54, 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, 55, 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; Vice President, Transmission, Xcel Energy Services Inc., August 2008 to March 2010.

Teresa S. Madden, 59, 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.

Marvin E. McDaniel, Jr., 55, 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; Vice President, Human Resources, Xcel Energy Services Inc., July 2007 to August 2009.

Timothy O'Connor, 55, 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 in May 2007 to July 2012.

Judy M. Poferl, 55, 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; Regional Vice President, NSP-Minnesota, September 2008 to August 2009; Managing Director, Government and Regulatory Affairs, Xcel Energy Services Inc., November 2007 to September 2008.

Jeffrey S. Savage, 43, 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; Director, Financial Reporting and Technical Accounting, Xcel Energy Services Inc., March 2007 to December 2009.

Mark E. Stoering, 54, 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.

George E. Tyson, II, 49, Senior Vice President, Treasurer, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Treasurer, Xcel Energy Inc., May 2004 to December 2014.

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Scott M. Wilensky, 58, 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; Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., August 2008 to September 2009.

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 of Directors is to identify, manage and mitigate material risk. Our Board employs an effective process for doing so, combining management and Board risk oversight. The guidelines on corporate governance and Board committee charters define the scope of review and inquiry for the Board and its committees regarding risk management. As provided below, management and each committee has responsibility for overseeing aspects of risk management and mitigation of the risk.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability, broadly considering our business, the utility industry, the domestic and global economy and the environment. 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 of the key risks and the discussion provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Management also provides information to the Board in presentations and communications over the course of the year.

The Board has assigned several important aspects of its governance and oversight to four standing committees to ensure issues and risks are well understood and effectively managed. While the Board as a whole reviews management’s key risk assessment and analyzes areas of potential future risk to Xcel Energy, the committees provide focused oversight of specific risks assigned to them. This provides robust and comprehensive risk management that is critical to successful execution of corporate strategy.

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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, 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 no longer makes operation of the units economic. 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., cleanup) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2014, 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 seeking to protect the environment may be adopted or become applicable to us, including but not limited to, regulation of mercury, NOx, SO_2, CO_2 and other GHGs, particulates and cooling water intake systems. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

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

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include 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 affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system 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 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.

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To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on GHGs, 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 in our utility operations. 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 or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Cost disallowances may arise as a result of prudence investigations (e.g., Monticello LCM/EPU project or the recent investigation of our PSIA 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, including additional environmental or climate change regulation, 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 in property, plant and equipment. As a result, we frequently need to access the debt and equity 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.

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Higher interest rates on short-term borrowings with variable interest rates or on incremental commercial paper issuances 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 retail customers will not pay their bills, which may lead to a reduction in liquidity and an eventual increase in bad debt expense. Retail credit risk is comprised of numerous factors including the 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. In addition, the CFTC’s rules permit us to deal in utility operations-related swaps with utility special entities and not be required to register as a swap dealer provided that our aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that we have not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Our current level of financial swap activity with special entities is significantly below this special entity de minimis threshold; therefore, we will not be classified as a swap dealer in our special entity activity. Swap transactions with non-special entities have a much higher level of activity considered to be de minimis, currently $8 billion, and our level of activity is well under this limit; therefore, we will not be classified as a swap dealer under the Dodd-Frank Act. We are currently reporting all of our swap transactions as part of the Dodd-Frank Act.

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 substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock 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 to these funding requirements 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.

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

If our utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock 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 to the consolidated financial statements, 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 authorized or anticipated costs. Any such disruption, if significant, would cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments would have a negative impact on our cash flows and could potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and such interruptions may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues vary in magnitude for each operating subsidiary depending upon unique operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation 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 of these radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or a substantial increase in operating expenses at NSP-Minnesota's nuclear plants. 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 with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities.

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.

Our utility operations file long-term resource plans with our regulators. These plans are based on numerous assumptions over the planning horizon such as: sales growth, customer usage, economic activity, costs, regulatory mechanisms, impact of technology, the installation of distributed generation, customer behavioral response and continuation of the existing utility business model. Given the uncertainty in these planning assumptions, there is a risk that the magnitude and timing of resource additions and demand may not coincide. This is particularly true in PSCo where the addition of customer-site solar installations introduces additional downward pressure on load growth. This could lead to under recovery of costs and excess resources to meet customer demand. Xcel Energy's aging infrastructure may pose a risk to system reliability and expose us to premature financial obligations. Xcel Energy is engaged in significant and ongoing infrastructure investment programs.

In addition, large industrial customers may leave our system and invest in their own on-site distributed generation or seek law changes to give them the authority to purchase directly from other suppliers or organized markets. The recent low natural gas price environment has caused some customers to consider their options in this area, particularly customers with industrial processes using steam. Wholesale customers may purchase directly from other suppliers and procure only transmission service from our utility subsidiaries. These circumstances provide for greater long-term planning uncertainty related to future load growth. Similarly, distributed solar generation may become an economic competitive threat to our load growth in the future. However, we believe the economics, absent significant subsidies, do not support such a trend in the near term unless a state mandates the purchase of such generation. Some states have considered such legislation.

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 intrastate and interstate 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.

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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.

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 under climate change laws at either the state or federal level in the future. The EPA is regulating GHGs under the CAA. The EPA has regulated GHG emissions from motor vehicles and has proposed regulations to reduce GHG emissions from existing power plants that are expected to become final in 2015, with state plans to achieve the EPA's goals due by 2017. Such regulations could impose substantial costs on our system.

The United States continues to participate in international negotiations related to the United Nations Framework Convention on Climate Change (UNFCCC). In 2014, the United States and China jointly announced GHG emissions goals. Further, the 20^{th} Conference of the Parties (COP) to the UNFCCC concluded with the objective of developing an agreement among countries on emission reductions at the 2015 COP. This could result in additional GHG regulation or reduction goals 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.

There are many uncertainties regarding when and in what form climate change legislation or regulations will be imposed. The impact of legislation and regulations will depend on a number of factors, including what GHG emission reduction goals are set, what flexibility is allowed to meet the goals, how and whether early action to reduce GHG emissions is credited, whether GHG sources in other sectors of the economy are regulated, the degree to which GHG offsets are recognized as compliance options, how any emission allowances would be allocated to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. In addition, international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements 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 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. In addition, NERC electric reliability standards are now 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.

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Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions both positively and negatively. 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 are 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 that could disrupt our ability to produce or distribute some portion of our energy products. 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, and 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, 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.

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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.

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. In addition, higher fuel costs could reduce customer demand and/or increase bad debt expense, which could also have a material impact on our results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. 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 for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Item 1B — Unresolved Staff Comments

None.

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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 2014 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	507	(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	554	
PI-Welch, Minn.				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Black Dog-Burnsville, Minn., 2 Units	Coal/Natural Gas	1955-1960	215	
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	271	
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453	
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	534	
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470	
Various locations, 17 Units	Natural Gas	Various	101	
Wind:				
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101	(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201	(c)
		Total	6,965	

(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 2014 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., 6 Units	Natural Gas	1973	290	

Hydro:			
Various locations, 63 Units	Hydro	Various	135
		Total	631

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

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PSCo

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)	
Steam:				
Cherokee-Denver, Colo., 2 Units	Coal	1957-1968	504	
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	
Zuni-Denver, Colo., 1 Unit	Coal	1948-1954	59	
Combustion Turbine:				
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	172	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
Wind:				
Ponnequin-Weld County, Colo., 37 Units	Wind	1999-2001	25	(d)
		Total	4,978	

(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.

(d) 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.

SPS

Station, Location and Unit	Fuel	Installed	Summer 2014 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

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Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2014:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	8,403	1,152	2,630	8,110
230 KV	1,803	—	12,162	9,312
161 KV	416	1,575	—	—
138 KV	—	—	92	—
115 KV	7,502	1,746	4,889	12,378
Less than 115 KV	84,090	32,408	75,110	23,294

Electric utility transmission and distribution substations at Dec. 31, 2014:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	356	201	229	433

Natural gas utility mains at Dec. 31, 2014:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	136	—	2,258	11
Distribution	9,931	2,316	21,844	—

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.

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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, 2014 was approximately 67,716. The following are the high and low stock prices based on the NYSE Composite Transactions for the quarters of 2014 and 2013 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.

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
2013	High	Low	Dividends
First quarter	$29.74	$26.77	$0.2700
Second quarter	31.79	27.38	0.2800
Third quarter	30.41	26.90	0.2800
Fourth quarter	29.40	27.14	0.2800

The following compares our cumulative TSR on common stock with the cumulative total return 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, 2009, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 48 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, 2009 in stock or index — including reinvestment of dividends. Fiscal years ending Dec. 31.

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	2009	2010	2011	2012	2013	2014
Xcel Energy Inc.	$100	$116	$142	$143	$155	$207
EEI Investor-Owned Electrics	100	107	128	131	148	191
S&P 500	100	115	117	136	180	205

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 2015 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, 2014:

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, 2014 — Jan. 31, 2014 (a)	18,874	$28.11	—	—
Feb. 1, 2014 — Dec. 31, 2014	—	—	—	—
Total	18,874		—	—

(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.

Item 6 — Selected Financial Data

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2014	2013	2012	2011	2010
Operating revenues	$11,686	$10,915	$10,128	$10,655	$10,311
Operating expenses	9,738	9,067	8,306	8,873	8,691
Net income	1,021	948	905	841	756
Earnings available to common shareholders	1,021	948	905	834	752
Weighted average common shares outstanding:					
Basic	503,847	496,073	487,899	485,039	462,052
Diluted	504,117	496,532	488,434	485,615	463,391
EPS:					
Basic	$2.03	$1.91	$1.86	$1.72	$1.63
Diluted	2.03	1.91	1.85	1.72	1.62
Dividends declared per common share	1.20	1.11	1.07	1.03	1.00
Total assets	36,958	33,907	31,141	29,497	27,388
Long-term debt (a)	11,500	10,911	10,144	8,849	9,263
Book value per share	20.20	19.21	18.19	17.44	16.76
Return on average common equity	10.3 %	10.3 %	10.4 %	10.1 %	9.8 %
Ratio of earnings to fixed charges (b)	3.3	3.1	2.8	2.8	2.7

Non-GAAP:					
Ongoing earnings [c]	$1,021	$968	$888	$841	$756

[a] Includes capital lease obligations.

[b] See Exhibit 12.01.

[c] See Item 7 for a reconciliation of ongoing earnings to GAAP earnings.

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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 in the following discussion and analysis 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,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including 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 slowdown 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 Inc. 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; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; 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.

Management’s Strategic Plans

Xcel Energy’s corporate strategy focuses on the following primary objectives:

- Improving utility performance;
- Driving operational excellence;
- Providing options and solutions to customers; and
- Investing for the future.

These objectives are designed to provide our investors an attractive total return and our customers with clean, safe, reliable energy at a competitive price. Below is a discussion of these objectives and how they support our overall strategy.

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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 of our states, our utility operating companies are earning less than the authorized ROE. This is referred to as an ROE gap. An ROE gap can be a result of 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 test year for rate cases, fluctuations in sales, the impact of weather, unanticipated cost increases, etc. Xcel Energy is focused on closing this gap over the next several years. As a result, we have established the following goals:

- Close the ROE gap by 50 basis points by 2018; and
- Derive 75 percent of our revenue from multi-year plans by 2017.

We are pursuing 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

Managing our operational performance and satisfying our customers has, and will continue to be, a fundamental priority. However, operational excellence also includes managing costs. By building on past success, leveraging technology, managing risks and continuously striving to improve our processes, we can bend the cost curve downward. Over the next five years, Xcel Energy is planning to implement cost saving measures which are intended to align increases in O&M expense more closely to sales growth. Our financial objective is to slow our annual O&M expense growth to approximately zero percent to two percent. However, we will not sacrifice reliability or safety to meet this initiative.

In addition, 50 percent of our workforce will be eligible to retire in the next ten years. Managing this workforce transition is key to our operational excellence objective.

Providing options and solutions to customers

Adapting to a changing environment is critical to our success. Our customers expect to be offered choices and we are committed to providing options and solutions that are fair and satisfy their needs. Environmental leadership is a core priority and is designed to meet customer and policy maker expectations for clean energy at a competitive price while creating shareholder value. We will continue to offer and expand our production of renewable energy, including wind and solar alternatives, and further develop 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 $14.5 billion from 2015 through 2019. This capital forecast will grow rate base at a compounded average annual rate of approximately 4.7 percent. Our capital investment plan includes needed 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 to our base capital investment plan, we are looking at potential incremental investments in natural gas assets and transmission projects through our recently established independent TransCos.

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 plan should allow Xcel Energy 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 a weather-normalized 2014 EPS of $2.00;
- Deliver annual dividend increases of five percent to seven percent;

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- 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 ten consecutive years and believe we are positioned to continue to achieve our value proposition. Our ongoing earnings have grown approximately 6.5 percent and our dividend has grown approximately 3.8 percent annually from 2005 through 2014. Prior to 2014, our objective was to grow the dividend two to four percent annually. 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 common 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	2014	2013	2012
PSCo	$0.90	$0.91	$0.90
NSP-Minnesota	0.80	0.79	0.70
SPS	0.26	0.23	0.22
NSP-Wisconsin	0.14	0.12	0.10
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.04
Regulated utility	2.14	2.09	1.96
Xcel Energy Inc. and other	(0.11)	(0.14)	(0.14)
Ongoing diluted EPS	2.03	1.95	1.82
SPS FERC complaint case orders	—	(0.04)	—
Prescription drug tax benefit	—	—	0.03
GAAP diluted EPS	$2.03	$1.91	$1.85

Ongoing earnings exclude adjustments for certain items. For 2013, the adjustment to GAAP earnings is related to the SPS FERC complaint case orders. For 2012, the adjustment is related to the Patient Protection and Affordable Care

Act. See below under Adjustments to GAAP Earnings and Note 12 and Note 6 to the consolidated financial statements for further discussion, respectively, for the 2013 and 2012 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.

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2013 Adjustment to GAAP Earnings

SPS FERC Orders — As a result of the orders issued in August 2013 by the FERC for a potential 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.

2012 Adjustment to GAAP Earnings

Prescription drug tax benefit — In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million, or $0.03 per share, of income tax benefit. See Note 6 to the consolidated financial statements for further discussion.

Earnings Adjusted for Certain Items (Ongoing EPS)

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.

2013 Comparison with 2012

Xcel Energy — Overall, ongoing earnings increased $0.13 per share for 2013. Ongoing earnings increased as a result of higher electric and gas margins due to rate increases in various states, the impact of favorable colder weather on the natural gas business and reduced interest charges. These positive factors were partially offset by planned increases in O&M expenses and depreciation.

PSCo — PSCo's ongoing earnings increased $0.01 per share for 2013. Ongoing earnings increased as a result of higher gas and electric margins primarily due to rate increases, the impact of cooler weather on natural gas margins and lower interest charges, partially offset by higher depreciation, O&M expenses and customer refunds related to the 2013 electric earnings test refund obligation.

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NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.09 per share for 2013. Ongoing earnings were positively impacted by electric rate increases in Minnesota and South Dakota, interim rates subject to refund in North Dakota, the impact of cooler winter weather and lower interest charges. These items were partially offset by higher O&M expenses.

SPS — SPS' ongoing earnings increased $0.01 per share for 2013. Electric rate increases in Texas and the gain associated with the sale of certain transmission assets to Sharyland were partially offset by higher depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2013. Higher ongoing earnings from electric and natural gas rates and cooler winter weather were partially offset by higher O&M expenses and depreciation.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2014 EPS compared with the same period in 2013.

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 2013 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

Diluted Earnings (Loss) Per Share	Dec. 31
2012 GAAP diluted EPS	$1.85
Prescription drug tax benefit	(0.03)
2012 ongoing diluted EPS	1.82
Components of change — 2013 vs. 2012	
Higher electric margins (excludes impact of SPS FERC complaint case orders)	0.18
Higher natural gas margins	0.08
Higher AFUDC — equity	0.05
Lower interest charges (excludes impact of SPS FERC complaint case orders)	0.04
Gain on sale of transmission assets (included in O&M expenses)	0.02
Higher O&M expenses (excludes gain on sale of transmission assets)	(0.14)
Higher depreciation and amortization	(0.06)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Higher taxes (other than income taxes)	(0.01)
2013 ongoing diluted EPS	1.95
SPS FERC complaint case orders	(0.04)

2013 GAAP diluted EPS	$1.91

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

ROE — 2014	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2014 ongoing and GAAP ROE	9.40 %	8.82 %	8.88 %	10.85 %	10.33 %

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ROE — 2013	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2013 ongoing ROE	9.66 %	9.24 %	9.03 %	10.61 %	10.50 %
SPS FERC complaint case orders	—	—	(1.54)	—	(0.22)
2013 GAAP ROE	9.66 %	9.24 %	7.49 %	10.61 %	10.28 %
ROE - 2012	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2012 ongoing ROE	9.92 %	8.77 %	9.44 %	9.62 %	10.24 %
Prescription drug tax benefit	0.38	—	—	—	0.19
2012 GAAP ROE	10.30 %	8.77 %	9.44 %	9.62 %	10.43 %

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)	2014	2013	2012
Ongoing earnings	$1,021.3	$968.4	$888.3
SPS FERC complaint case orders (2013) and prescription drug tax benefit (2012)	—	(20.2)	16.9
GAAP earnings	$1,021.3	$948.2	$905.2
Diluted Earnings (Loss) Per Share	2014	2013	2012
Ongoing diluted EPS	$2.03	$1.95	$1.82
SPS FERC complaint case orders (2013) and prescription drug tax benefit (2012)	—	(0.04)	0.03
GAAP diluted EPS	$2.03	$1.91	$1.85

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

(Millions of Dollars)	2014	2013	2012
GAAP income (loss) by segment			
Regulated electric income	$890.5	$850.7	$851.9
Regulated natural gas income	128.6	123.7	98.1
Other income [(a)]	59.5	44.6	22.1
Xcel Energy Inc. and other costs [(a)]	(57.3)	(70.8)	(66.9)
Total net income	$1,021.3	$948.2	$905.2
Contributions to Diluted Earnings (Loss) Per Share	2014	2013	2012
GAAP earnings (loss) by segment			
Regulated electric	$1.77	$1.71	$1.74
Regulated natural gas	0.25	0.25	0.20
Other [(a)]	0.12	0.09	0.05
Xcel Energy Inc. and other costs [(a)]	(0.11)	(0.14)	(0.14)
Total diluted EPS	$2.03	$1.91	$1.85

[(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.

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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:

	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2012 vs. Normal	2013 vs. 2012
HDD	7.8 %	6.5 %	0.4 %	(15.9)%	25.8 %
CDD	(2.6)	24.7	(20.3)	46.1	(13.6)
THI	(11.9)	21.8	(24.2)	36.1	(9.7)

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

	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2012 vs. Normal	2013 vs. 2012
Retail electric	$0.010	$0.088	$(0.078)	$0.081	$0.007
Firm natural gas	0.019	0.021	(0.002)	(0.033)	0.054
Total	$0.029	$0.109	$(0.080)	$0.048	$0.061

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:

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

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

Weather-normalized Electric Growth

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- 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.

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- 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 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.

Weather-normalized sales for 2015 are projected to increase approximately 1.0 percent for retail electric customers and to decline approximately 2.0 percent for retail firm natural gas customers.

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual (Without 2012 Leap Day)					
Electric residential	1.4 %	3.9 %	0.9 %	1.1 %	1.3 %
Electric C&I	0.3	1.0	1.8	0.3	(0.7)
Total retail electric sales	0.6	1.9	1.5	0.5	(0.1)
Firm natural gas sales	21.9	30.0	N/A	17.8	29.1

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized (Without 2012 Leap Day)					
Electric residential	0.5 %	0.5 %	0.7 %	1.3 %	(0.2)%
Electric C&I	0.4	0.9	2.1	0.9	(1.1)
Total retail electric sales	0.4	0.8	1.7	1.0	(0.8)
Firm natural gas sales	3.8	5.9	N/A	3.3	4.2

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	1.1 %	3.6 %	0.6 %	0.8 %	1.1 %
Electric C&I	—	0.7	1.5	—	(1.0)
Total retail electric sales	0.3	1.6	1.3	0.3	(0.4)
Firm natural gas sales	21.3	29.4	N/A	17.3	28.5

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.2 %	0.2 %	0.5 %	1.0 %	(0.5)%
Electric C&I	0.1	0.6	1.8	0.7	(1.4)
Total retail electric sales	0.1	0.5	1.5	0.7	(1.1)
Firm natural gas sales	3.3	5.3	N/A	2.8	3.7

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)	2014	2013	2012
Electric revenues	$9,466	$9,034	$8,517
Electric fuel and purchased power	(4,210)	(4,019)	(3,624)

Electric margin	$5,256	$5,015	$4,893

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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)	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 include final rates in Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota, subject to and net of estimated provision for refund. See Note 12 to the consolidated financial statements.

(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. See Note 12 to the consolidated financial statements.

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

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Electric Revenues

(Millions of Dollars)	2013 vs. 2012
Fuel and purchased power cost recovery	$360
Retail rate increases [a]	229
Transmission revenue	68
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Firm wholesale	(36)
Conservation and DSM program incentives	(24)
Trading	(19)
SPS FERC complaint case orders [b]	(6)
Other, net	(11)
Total increase in ongoing electric revenues	543
SPS FERC complaint case orders [b]	(26)
Total increase in GAAP electric revenues	$517

2013 Comparison with 2012 — Electric revenues increased primarily due to higher fuel and purchased power cost recovery, which is offset in operating expense, and various rate increases across all of the utility subsidiaries.

Electric Margin

(Millions of Dollars)	2013 vs. 2012
Retail rate increases [a]	$229
Transmission revenue, net of costs	36
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Conservation and DSM program incentives	(24)
Firm wholesale	(24)
Trading margin	(12)
SPS FERC complaint case orders [b]	(6)
Other, net	(33)
Total increase in ongoing electric margin	148
SPS FERC complaint case orders [b]	(26)
Total increase in GAAP electric margin	$122

(a) The retail rate increases include final rates in Minnesota, Colorado, Wisconsin, South Dakota and Texas and interim rates, subject to refund, in North Dakota. The Minnesota rate increase is net of a provision for customer refunds of $131 million for the twelve months ended Dec. 31, 2013 based on the final rate order received for the 2013 electric rate case. Due to the order, there was a reduction in revenues and expenses of approximately $40 million, primarily related to depreciation of $32 million and O&M expense of $8 million in 2013.

(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. See Note 12 to the consolidated financial statements.

2013 Comparison to 2012 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

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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)	2014	2013	2012
Natural gas revenues	$2,143	$1,805	$1,537
Cost of natural gas sold and transported	(1,372)	(1,083)	(881)
Natural gas margin	$771	$722	$656

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)	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.

Natural Gas Revenues

(Millions of Dollars)	2013 vs. 2012
Purchased natural gas adjustment clause recovery	$198
Estimated impact of weather	42
Retail rate increases (Colorado and Wisconsin)	15
Retail sales growth	9
Conservation and DSM program incentives	5
Conservation and DSM program revenues (offset by expenses)	4
Other, net	(5)
Total increase in natural gas revenues	$268

2013 Comparison to 2012 — Natural gas revenues increased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

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Natural Gas Margin

(Millions of Dollars)	2013 vs. 2012
Estimated impact of weather	$42
Retail rate increases (Colorado and Wisconsin)	15
Retail sales growth	9
Conservation and DSM program incentive	5
Conservation and DSM program revenues (offset by expenses)	4
Other, net	(9)
Total increase in natural gas margin	$66

2013 Comparison to 2012 — Natural gas margins increased primarily due to cooler winter weather and rate increases in Colorado and Wisconsin.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $60.8 million, or 2.7 percent, for 2014 compared with 2013, and $97.4 million, or 4.5 percent, for 2013 compared with 2012. The following tables summarize the changes 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.

(Millions of Dollars)	2013 vs. 2012
Electric and gas distribution expenses	$44
Nuclear plant operations and amortization	33
Transmission costs	13
Employee benefits	7
Gain on sale of transmission assets	(14)
Other, net	14
Total increase in O&M expenses	$97

2013 Comparison to 2012 — The increase in O&M expenses for 2013 was largely driven by the following:

- Electric and gas distribution expenses were primarily driven by increased maintenance activities due to vegetation management, storms and outages;
- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs;

- Higher employee benefits related primarily to increased pension expense; and
- See Note 12 to the consolidated financial statements for further discussion of the gain on sale of transmission assets.

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Conservation and DSM Program Expenses — 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. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — 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. See further discussion within Note 12 to the consolidated financial statements.

Depreciation and amortization increased $51.8 million, or 5.6 percent, for 2013 compared with 2012. The increase is primarily attributable to normal system expansion, which was partially offset by reductions related to the final rate order received for the 2013 Minnesota electric rate case that reduced depreciation expense by approximately $32 million for 2013.

Taxes (Other Than Income Taxes) — 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.

Taxes (other than income taxes) increased $11.6 million, or 2.8 percent, for 2013 compared with 2012. The annual increase is due to higher property taxes primarily in Colorado and Texas.

AFUDC, Equity and Debt — 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.

AFUDC increased $28.7 million for 2013 compared with 2012. The increase is primarily due to construction related to the CACJA and the expansion of transmission facilities.

Interest Charges — 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.

Interest charges decreased $26.4 million, or 4.4 percent, for 2013 compared with 2012. The decrease is primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels, $4 million of interest associated with the customer refund at SPS based on the August 2013 FERC orders, $5 million of interest associated with customer refunds in Minnesota for the 2013 electric rate case 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 $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.

Income tax expense increased $33.8 million for 2013 compared with 2012. The increase in income tax expense was primarily due to higher pretax earnings in 2013, a tax benefit for a carryback in 2012 and for the restoration in 2012 of a portion of the tax benefit associated with federal subsidies for prescription drug plans that was previously written off in 2010. These were partially offset in 2013 by a tax benefit for a carryback claim related to 2013, R&E credits and increased permanent plant-related reductions. The ETR was 33.8 percent for 2013 compared with 33.2 percent for 2012. The higher ETR for 2013 was primarily due to the adjustments referenced above. See Note 6 to the consolidated financial statements for further discussion.

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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)	2014	2013	2012
Xcel Energy Inc. financing costs	$(51.8)	$(62.9)	$(71.5)
Eloigne [(a)]	(0.5)	(0.8)	3.8
Xcel Energy Inc. taxes and other results	(5.0)	(7.1)	0.8
Total Xcel Energy Inc. and other costs	$(57.3)	$(70.8)	$(66.9)

	Contribution to Xcel Energy's EPS		
(Earnings per Share)	2014	2013	2012
Xcel Energy Inc. financing costs	$(0.10)	$(0.13)	$(0.15)
Eloigne [(a)]	—	—	0.01
Xcel Energy Inc. taxes and other results	(0.01)	(0.01)	—
Total Xcel Energy Inc. and other costs	$(0.11)	$(0.14)	$(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.

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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. 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 2014;
- $275 million in 2013; and

- $263 million in 2012.

Xcel Energy estimates an average annual expense of approximately $339 million from 2015 through 2019 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:

- $373 million in 2014;
- $517 million in 2013; and
- $255 million in 2012.

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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 plans of MGP 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.

There are emission controls, known as BART, for industrial facilities releasing emissions that reduce visibility in certain national parks and wilderness areas. Xcel Energy generating facilities in Minnesota and Colorado are subject to BART requirements. Further, generating facilities throughout the Xcel Energy territory are subject to state and federal mercury reduction requirements. In addition, the EPA has proposed to require installation of dry scrubbers on Tolk Units 1 and 2 under a federal visibility plan for Texas.

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 account and report assets and liabilities consistent with the recovery of those incurred costs in rates and 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 they are probable of future recovery from customers. 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.

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As of Dec. 31, 2014 and 2013, Xcel Energy has recorded regulatory assets of $3.2 billion and $2.9 billion and regulatory liabilities of $1.6 billion and $1.3 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these 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 also 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 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 increase in 2015 and decline in the following few years. Funding requirements are expected to decrease in 2015 and then be flat in the following years. While investment returns exceeded the assumed levels in 2012 and again in 2014, investment returns were slightly below the assumed levels in 2013. 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 2014.

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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 $140.4 million in 2015 and $129.6 million in 2016, while the actual pension costs were $126.5 million in 2014 and $151.8 million in 2013. The expected increase in the 2015 cost is due primarily to the impact of a potential settlement in the most recent Colorado electric rate case, updating the mortality tables and a decrease in the discount rate which were offset by the reduced amortization of prior service costs and other historic loss amounts, including the 2008 market loss. 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 as a result of increases in assets via planned contributions and the subsequent 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.

At Dec. 31, 2014, Xcel Energy set the rate of return on assets used to measure pension costs at 7.09 percent, which is a four basis point increase from Dec. 31, 2013. The rate of return used to measure postretirement health care costs is 5.80 percent at Dec. 31, 2014 and is a 137 basis point decrease from Dec. 31, 2013. 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, 2014 pension and postretirement health care obligations at 4.11 percent and 4.08 percent, which represent a 64 basis point and 74 basis point decrease from Dec. 31, 2013, 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, 2014, 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 2012 through 2015:

- $90.0 million in January 2015;
- $130.6 million in 2014;
- $192.4 million in 2013; and
- $198.1 million in 2012.

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, 2014, a one-percent change would result in the following impact on 2015 pension costs:

	Pension Costs	
(Millions of Dollars)	+1%	-1%

Rate of return	$(20.6)	$20.6
Discount rate [a]	(10.6)	13.4

[a] These costs include the effects of regulation.

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Effective Jan. 1, 2015, the initial medical trend assumption was decreased from 7.00 percent to 6.50 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is four 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 $17.1 million, $17.6 million and $47.1 million during 2014, 2013 and 2012, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately $12.8 million during 2015.

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 based on expense 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 Colorado electric retail and Texas jurisdictions 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.
- Beginning in 2015, the Colorado electric retail jurisdiction expects to recognize additional expense associated with a pending order to accelerate amortization of the qualified prepaid pension asset. A regulatory liability would be recorded to account for any resulting regulatory obligation.

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 $2,038 million and $1,628 million as of Dec. 31, 2014 and 2013, 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. A decision on the filing is expected in late 2015 or early 2016.

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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 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, 2014.

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.

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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, 2014, the fair values by source for net commodity trading contract assets were as follows:

(Thousands of Dollars)	Futures / Forwards Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota	1	$6,359	$8,238	$1,401	$1,088	$17,086
	2	4,400	—	—	—	4,400
		$10,759	$8,238	$1,401	$1,088	$21,486

(Thousands of Dollars)	Options Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$325	$—	$—	$—	$325

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)	2014	2013
Fair value of commodity trading net contract assets outstanding at Jan. 1	$30,514	$28,314
Contracts realized or settled during the period	(12,698)	(6,665)
Commodity trading contract additions and changes during the period	3,995	8,865
Fair value of commodity trading net contract assets outstanding at Dec. 31	$21,811	$30,514

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. At Dec. 31, 2013, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.6 million, whereas a 10 percent decrease would increase pretax income by approximately $0.6 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
2014	$0.57	$3.00	$0.61	$4.06	$ 0.13
2013	0.29	3.00	0.41	1.65	<0.01

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 13 percent of its 2015 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. In 2014, NSP-Minnesota arranged for and took delivery of material from alternate sources that were not impacted by these world events. These alternate 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 34 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 2015.

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, 2014 and 2013, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $10.4 million and $8.3 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, 2014, 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 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, 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. At Dec. 31, 2013, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $15.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2.6 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, 2014. 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, 2014.

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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 3.7 percent and 41.0 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2014.

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 $67.0 million and $10.9 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2014.

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, 2014.

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 $165.5 million in the nuclear decommissioning fund at Dec. 31, 2014 (approximately 9.2 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)	2014	2013	2012
Net cash provided by operating activities	$2,648	$2,584	$2,005

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.

Net cash provided by operating activities increased by $579 million for 2013 as compared to 2012. The increase was primarily the result of higher net income, changes in working capital due to the timing of payments and receipts, net changes in regulatory assets and liabilities, and payments mainly related to interest rate swap settlements in 2012.

(Millions of Dollars)	2014	2013	2012
Net cash used in investing activities	$(3,117)	$(3,213)	$(2,333)

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.

Net cash used in investing activities increased by $880 million for 2013 as compared to 2012. The increase was primarily the result of higher capital expenditures for several major construction projects including the Monticello nuclear EPU project as well as the PI steam generator replacement and certain other transmission line projects. Other differences mainly related to changes in restricted cash.

(Millions of Dollars)	2014	2013	2012
Net cash provided by financing activities	$442	$654	$350

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.

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Net cash provided by financing activities increased by $654 million for 2013 as compared to 2012. The increase was primarily due to the issuance of more common stock during 2013, lower repayments of previously existing long-term debt, which was partially offset by reductions in long-term and short-term borrowing.

See discussion of trends, commitments and uncertainties with the potential for 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 current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2019 are shown in the table below.

	Actual	Forecast					
(Millions of Dollars)	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
By Subsidiary							
NSP-Minnesota	$1,159	$1,625	$990	$975	$845	$950	$5,385
PSCo	1,064	950	820	815	885	1,010	4,480
SPS	542	570	710	735	595	565	3,175
NSP-Wisconsin	290	230	260	300	325	325	1,440
Total capital expenditures	$3,055	$3,375	$2,780	$2,825	$2,650	$2,850	$14,480
By Function	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
Electric transmission	$972	$875	$780	$905	$975	$1,000	$4,535
Electric generation	710	1,190	630	620	415	450	3,305
Electric distribution	545	605	630	640	650	680	3,205
Natural gas	525	370	370	305	355	380	1,780
Nuclear fuel	154	90	120	120	65	150	545
Other	149	245	250	235	190	190	1,110
Total capital expenditures	$3,055	$3,375	$2,780	$2,825	$2,650	$2,850	$14,480

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.

The current estimated financing plans to fund capital expenditures of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2019 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$11,500
New Debt**	2,605
Equity from Dividend Reinvestment Program (DRIP) and Benefit Programs	375

2015-2019 Capital Expenditures	$14,480
Maturing Debt	$2,995

*Cash from operations, net of dividend and pension funding.
**Reflects a combination of short and long-term debt.

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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, 2014. 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)]	$20,295,497	$788,787	$2,069,075	$2,483,533	$14,954,102
Capital lease obligations	352,185	17,787	32,143	29,154	273,101
Operating leases [(b)(c)]	3,103,660	254,550	467,423	463,693	1,917,994
Unconditional purchase obligations [(d)]	10,101,197	2,023,394	2,555,760	1,406,598	4,115,445
Other long-term obligations, including current portion [(e)]	200,289	52,207	83,775	64,307	—
Payments to vendors in process	35,151	35,151	—	—	—
Short-term debt	1,019,500	1,019,500	—	—	—
Total contractual cash obligations [(f)(g)(h)]	$35,107,479	$4,191,376	$5,208,176	$4,447,285	$21,260,642

(a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2014, 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, 2014, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $62.2 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 $228.3 million, $425.4 million, $424.6 million and $1.8 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 as well as uncertain tax positions.

(f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately $3.6 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table.

(g) In January 2015, contributions of $90.0 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 $12.8 million to the postretirement health care plans during 2015. 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. 18, 2015, Xcel Energy announced a quarterly dividend of $0.32 per share, which represented an increase of 6.7 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.

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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. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation, there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. An entity may deal in utility operations-related swaps and not be required to register as a swap dealer provided that the aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that the entity has not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy is currently meeting all other reporting requirements.

SPP FTR Margining Requirements — The SPP conducted its first annual FTR auction in the spring of 2014 associated with the implementation of the SPP IM. The process for transmission owners involves the receipt of Auction Revenue Rights (ARRs) and, if elected by the transmission owner, conversion of those ARRs to firm FTRs. SPP requires that the transmission owner post collateral for the conversion of ARRs to FTRs. At Dec. 31, 2014, SPS had a $30 million letter of credit posted with SPP, which was a reduction from the initial requirement of $41 million.

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, 2014	Dec. 31, 2013
Fair value of pension assets	$3,084	$3,010
Projected pension obligation [a]	3,747	3,441
Funded status	$(663)	$(431)

[a] Excludes nonqualified plan of $47 million and $37 million at Dec. 31, 2014 and 2013, respectively.

Pension Assumptions	2014	2013
Discount rate	4.11 %	4.75 %
Expected long-term rate of return	7.09	7.05

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, 2014 and 2013, there was $3.3 million and $21.7 million of cash held in these accounts, respectively.

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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, 2014
Borrowing limit	$2,750
Amount outstanding at period end	1,020
Average amount outstanding	802
Maximum amount outstanding	1,021
Weighted average interest rate, computed on a daily basis	0.36 %
Weighted average interest rate at end of period	0.56

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013	Year Ended Dec. 31, 2012
Borrowing limit	$2,750	$2,450	$2,450
Amount outstanding at period end	1,020	759	602
Average amount outstanding	841	481	403
Maximum amount outstanding	1,200	1,160	634
Weighted average interest rate, computed on a daily basis	0.33 %	0.31 %	0.35 %
Weighted average interest rate at end of period	0.56	0.25	0.36

Credit Facilities — In October 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks, replacing their previous five-year credit agreements. 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. 18, 2015, 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.	$1,000.0	$505.0	$495.0	$0.2	$495.2
PSCo	700.0	243.4	456.6	0.4	457.0
NSP-Minnesota	500.0	139.1	360.9	1.0	361.9
SPS	400.0	138.0	262.0	1.0	263.0
NSP-Wisconsin	150.0	51.0	99.0	0.9	99.9
Total	$2,750.0	$1,076.5	$1,673.5	$3.5	$1,677.0

(a) These credit facilities have been amended to extend the maturity to 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.

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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, 2014 and 2013, Xcel Energy Inc. had approximately 506 million shares and 498 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, 2014 and 2013.

Xcel Energy Inc. and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy Inc. has an effective automatic shelf registration statement filed in August 2012, which does not contain a limit on issuance capacity. However, Xcel Energy Inc.'s ability to issue securities is limited by authority granted by the Board of Directors, which currently authorizes the issuance of up to an additional $900 million of debt and common equity securities.
- NSP-Minnesota has an automatic shelf registration statement filed in December 2013, which does not contain a limit on issuance capacity. However, NSP-Minnesota's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $750 million of debt securities.
- NSP-Wisconsin has $100 million of debt securities remaining under its currently effective shelf registration statement, which was filed in December 2013.
- PSCo has an automatic shelf registration statement filed in October 2013, which does not contain a limit on issuance capacity. However, PSCo's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $700 million of debt securities.
- SPS has $150 million of debt securities remaining under its currently effective shelf registration statement, which was filed in April 2013. SPS intends to register additional debt securities in 2015.

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 2014, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044;
- In May, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June, NSP-Wisconsin issued $100 million of 3.30 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. As a result, Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity, beyond its DRIP and benefit programs, over the next five years based on its current capital expenditure plan.

Financing Plans — 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.

During 2015, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $500 million of senior unsecured bonds;
- PSCo plans to issue approximately $250 million of first mortgage bonds;

- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- SPS plans to issue approximately $250 million of first mortgage bonds; and
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds.

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

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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 2015 ongoing earnings guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- If the MPUC orders a disallowance in the Monticello prudence review, Xcel Energy would exclude the associated charge from ongoing earnings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2.0 percent.
- Capital rider revenue is projected to increase by $160 million to $170 million over 2014 levels. The projected capital rider revenue reflects the transfer of the CACJA project from base rates to the rider per the settlement in the Colorado electric rate case. The settlement is pending CPUC approval.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 levels.
- Depreciation expense is projected to increase $160 million to $180 million over 2014 levels, reflecting the originally proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota’s moderation plan in the Minnesota electric rate case.
- Property taxes are projected to increase approximately $60 million to $70 million over 2014 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2014 levels.
- AFUDC — equity is projected to decline approximately $35 million to $45 million from 2014 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 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 weather-normalized, ongoing 2014 EPS of $2.00;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent of annual ongoing EPS; 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.

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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, 2014. 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, 2014, 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. 20, 2015	Feb. 20, 2015

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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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, 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 20, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015

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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, 2014, 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, 2014, 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, 2014 of the Company and our report dated February 20, 2015 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015

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

	Year Ended Dec. 31		
	2014	2013	2012
Operating revenues			
Electric	$9,465,890	$9,034,045	$8,517,296
Natural gas	2,142,738	1,804,679	1,537,374
Other	77,507	76,198	73,553
Total operating revenues	11,686,135	10,914,922	10,128,223
Operating expenses			
Electric fuel and purchased power	4,210,142	4,018,672	3,623,935
Cost of natural gas sold and transported	1,372,479	1,082,751	880,939
Cost of sales — other	34,352	33,323	29,067
Operating and maintenance expenses	2,334,379	2,273,532	2,176,095
Conservation and demand side management program expenses	301,772	260,726	260,527
Depreciation and amortization	1,019,045	977,863	926,053
Taxes (other than income taxes)	465,836	420,500	408,924
Total operating expenses	9,738,005	9,067,367	8,305,540
Operating income	1,948,130	1,847,555	1,822,683
Other income, net	5,296	2,972	6,175
Equity earnings of unconsolidated subsidiaries	30,151	30,020	29,971
Allowance for funds used during construction — equity	89,750	87,683	62,840
Interest charges and financing costs			
Interest charges — includes other financing costs of $22,986, $30,135 and $24,087, respectively	566,608	575,199	601,552
Allowance for funds used during construction — debt	(38,402)	(39,179)	(35,315)
Total interest charges and financing costs	528,206	536,020	566,237
Income before income taxes	1,545,121	1,432,210	1,355,432
Income taxes	523,815	483,976	450,203
Net income	$1,021,306	$948,234	$905,229
Weighted average common shares outstanding:			
Basic	503,847	496,073	487,899
Diluted	504,117	496,532	488,434
Earnings per average common share:			
Basic	$2.03	$1.91	$1.86
Diluted	2.03	1.91	1.85
Cash dividends declared per common share	$1.20	$1.11	$1.07

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2014	2013	2012
Net income	$1,021,306	$948,234	$905,229
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 $(4,687), $1,746 and $(4,898), respectively	(7,517)	1,408	(7,005)
Amortization of losses included in net periodic benefit cost, net of tax of $2,159, $4,151 and $2,567, respectively	3,495	3,306	3,694
	(4,022)	4,714	(3,311)
Derivative instruments:			
Net fair value (decrease) increase, net of tax of $(103), $17 and $(12,593), respectively	(163)	12	(19,200)
Reclassification of losses to net income, net of tax of $1,493, $2,541 and $2,687, respectively	2,288	1,476	3,697
	2,125	1,488	(15,503)
Marketable securities:			
Net fair value increase, net of tax of $21, $117 and $135, respectively	33	176	196
Other comprehensive (loss) income	(1,864)	6,378	(18,618)
Comprehensive income	$1,019,442	$954,612	$886,611

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2014	2013	2012
Operating activities			
Net income	$1,021,306	$948,234	$905,229
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,036,515	1,001,843	943,702
Conservation and demand side management program amortization	6,033	6,531	7,258
Nuclear fuel amortization	114,542	98,089	102,651
Deferred income taxes	569,378	515,062	508,094
Amortization of investment tax credits	(5,543)	(5,753)	(6,610)
Allowance for equity funds used during construction	(89,750)	(87,683)	(62,840)
Equity earnings of unconsolidated subsidiaries	(30,151)	(30,020)	(29,971)
Dividends from unconsolidated subsidiaries	36,707	36,416	33,470
Provision for bad debts	42,765	37,627	33,808
Share-based compensation expense	32,189	24,613	26,970
Gain on sale of transmission assets	—	(13,661)	—
Prairie Island EPU and SmartGridCity	—	—	20,766
Net realized and unrealized hedging and derivative transactions	5,506	(4,704)	(85,308)
Changes in operating assets and liabilities:			
Accounts receivable	(125,146)	(108,911)	(197,236)
Accrued unbilled revenues	(41,262)	(23,867)	25,377
Inventories	(20,558)	(43,588)	82,658
Other current assets	(111,300)	(18,071)	(30,737)
Accounts payable	(53,242)	132,441	(100,327)
Net regulatory assets and liabilities	195,823	141,325	5,866
Other current liabilities	137,147	126,555	42,914
Pension and other employee benefit obligations	(101,457)	(156,369)	(183,922)
Change in other noncurrent assets	44,364	(9,998)	(33,151)
Change in other noncurrent liabilities	(15,674)	17,925	(3,905)
Net cash provided by operating activities	2,648,192	2,584,036	2,004,756
Investing activities			
Utility capital/construction expenditures	(3,199,791)	(3,395,325)	(2,570,209)
Allowance for equity funds used during construction	89,750	87,683	62,840
Proceeds from sale of transmission assets	—	37,118	—
Proceeds from insurance recoveries	6,000	90,000	97,835
Purchases of investments in external decommissioning fund	(595,569)	(1,481,881)	(1,102,025)
Proceeds from the sale of investments in external decommissioning fund	588,430	1,461,291	1,087,076
Investment in WYCO Development LLC	(2,376)	(7,504)	(980)
Change in restricted cash	—	—	95,287
Other, net	(3,695)	(4,766)	(2,766)
Net cash used in investing activities	(3,117,251)	(3,213,384)	(2,332,942)
Financing activities			
Proceeds from short-term borrowings, net	260,500	157,000	383,000
Proceeds from issuance of long-term debt	837,584	1,431,895	1,790,131

Repayments of long-term debt, including reacquisition premiums	(275,948)	(652,451)	(1,302,763)
Proceeds from issuance of common stock	180,798	231,767	8,050
Repurchase of common stock	—	—	(18,529)
Purchase of common stock for settlement of equity awards	—	—	(23,307)
Dividends paid	(561,411)	(514,042)	(486,757)
Net cash provided by financing activities	441,523	654,169	349,825
Net change in cash and cash equivalents	(27,536)	24,821	21,639
Cash and cash equivalents at beginning of period	107,144	82,323	60,684
Cash and cash equivalents at end of period	$79,608	$107,144	$82,323
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$(512,602)	$(514,911)	$(563,517)
Cash (paid) received for income taxes, net	(4,542)	17,188	(9,570)
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	$417,473	$452,453	$289,802
Issuance of common stock for reinvested dividends and 401(k) plans	62,078	56,950	67,723

See Notes to Consolidated Financial Statements

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

	Dec. 31 2014	2013
Assets		
Current assets		
Cash and cash equivalents	$79,608	$107,144
Accounts receivable, net	826,506	744,160
Accrued unbilled revenues	728,492	687,230
Inventories	597,183	576,538
Regulatory assets	444,058	417,801
Derivative instruments	85,723	91,707
Deferred income taxes	246,210	341,202
Prepaid taxes	185,488	60,560
Prepayments and other	171,112	191,698
Total current assets	3,364,380	3,218,040
Property, plant and equipment, net	28,756,916	26,122,159
Other assets		
Nuclear decommissioning fund and other investments	1,832,640	1,755,990
Regulatory assets	2,774,216	2,509,218
Derivative instruments	53,775	84,842
Other	175,957	217,241
Total other assets	4,836,588	4,567,291
Total assets	$36,957,884	$33,907,490
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$257,726	$280,763
Short-term debt	1,019,500	759,000
Accounts payable	1,173,006	1,261,238
Regulatory liabilities	410,729	274,769
Taxes accrued	396,615	378,766
Accrued interest	158,536	159,372
Dividends payable	151,720	139,432
Derivative instruments	21,632	23,382
Other	475,119	377,776
Total current liabilities	4,064,583	3,654,498
Deferred credits and other liabilities		
Deferred income taxes	5,852,988	5,331,046
Deferred investment tax credits	73,696	79,239
Regulatory liabilities	1,163,429	1,059,395
Asset retirement obligations	2,446,631	1,815,390
Derivative instruments	183,936	209,224
Customer advances	256,945	275,555

Pension and employee benefit obligations	936,907	769,222
Other	264,653	237,217
Total deferred credits and other liabilities	11,179,185	9,776,288
Commitments and contingencies		
Capitalization		
Long-term debt	11,499,634	10,910,754
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 505,733,267 and 497,971,508 shares outstanding at Dec. 31, 2014 and 2013, respectively	1,264,333	1,244,929
Additional paid in capital	5,837,330	5,619,313
Retained earnings	3,220,958	2,807,983
Accumulated other comprehensive loss	(108,139)	(106,275)
Total common stockholders' equity	10,214,482	9,565,950
Total liabilities and equity	$36,957,884	$33,907,490

See Notes to Consolidated Financial Statements

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

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value				
Balance at Dec. 31, 2011	486,494	$1,216,234	$5,327,443	$2,032,556	$ (94,035)	$8,482,198
Net income				905,229		905,229
Other comprehensive loss					(18,618)	(18,618)
Dividends declared on common stock				(523,969)		(523,969)
Issuances of common stock	2,166	5,415	28,219			33,634
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity rewards			(23,307)			(23,307)
Share-based compensation			37,439			37,439
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

See Notes to Consolidated Financial Statements

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

	Dec. 31 2014	2013
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	$250,000	$250,000
March 1, 2018, 5.25%	500,000	500,000
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	—
Other	47	48
Unamortized discount	(11,365)	(11,316)
Total	4,188,682	3,888,732
Less current maturities	250,013	2
Total NSP-Minnesota long-term debt	$3,938,669	$3,888,730
PSCo		
First Mortgage Bonds, Series due:		
April 1, 2014, 5.5%	$—	$275,000
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
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	—
Capital lease obligations, through 2060, 11.2% — 14.3%	172,209	179,444
Unamortized discount	(11,480)	(11,301)
Total	3,890,229	3,872,643
Less current maturities	8,178	282,143
Total PSCo long-term debt	$3,882,051	$3,590,500
SPS		

First Mortgage Bonds, Series due:		
June 15, 2024, 3.3%	$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 discount	(309)	(135)
Total	1,349,691	1,199,865
Less current maturities	—	—
Total SPS long-term debt	$1,349,691	$1,199,865

See Notes to Consolidated Financial Statements

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

	Dec. 31 2014	2013
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	$150,000	$150,000
June 15, 2024, 3.3%	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%	523	558
Other	1,687	1,760
Unamortized discount	(2,519)	(2,321)
Total	568,291	468,597
Less current maturities	1,235	107
Total NSP-Wisconsin long-term debt	$567,056	$468,490
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2015-2052, 0% — 8%	$32,037	$37,490
Total	32,037	37,490
Less current maturities	1,316	1,128
Total other subsidiaries long-term debt	$30,721	$36,362
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
May 15, 2020, 4.7%	550,000	550,000
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	(69,470)	(72,087)
Unamortized discount	(6,078)	(7,702)
Total	1,728,431	1,724,190
Less current maturities (including elimination of PSCo capital lease obligation)	(3,015)	(2,617)
Total Xcel Energy Inc. long-term debt	$1,731,446	$1,726,807
Total long-term debt	$11,499,634	$10,910,754
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 505,733,267 and 497,971,508 shares outstanding at Dec. 31, 2014 and 2013, respectively	$1,264,333	$1,244,929
Additional paid in capital	5,837,330	5,619,313
Retained earnings	3,220,958	2,807,983

Accumulated other comprehensive loss	(108,139)	(106,275)
Total common stockholders' equity	$10,214,482	$9,565,950

[a] Pollution control financing.
[b] Resource recovery financing.

See Notes to Consolidated Financial Statements

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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 2014, 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, 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.

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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. The revenues and charges from these RTOs related to serving retail and wholesale electric customers comprising the native load of the NSP-System and SPS are recorded on a net basis within cost of sales. 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.

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.

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in conserving energy and reducing peak demand 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, air conditioner controls and energy-efficient heating and cooling appliances.

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. 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.

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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 2.7, 2.9, and 2.8 percent for the years ended Dec. 31, 2014, 2013 and 2012, 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 filed its most recent triennial nuclear decommissioning studies with the MPUC in December 2014. 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), as well as future disposal costs of spent nuclear fuel 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.

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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. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. 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 3 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. The sales of RECs for trading purposes are recorded in electric utility operating revenues, net of the cost of the RECs, transaction costs, and amounts credited to customers under margin-sharing mechanisms.

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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 revenues 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. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and 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.

Reclassifications — Certain previously reported amounts have been reclassified to conform to the current year presentation.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2014 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. This guidance, which includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers, will be effective for interim and annual reporting periods beginning after Dec. 15, 2016. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Accounts receivable, net		
Accounts receivable	$884,225	$797,267
Less allowance for bad debts	(57,719)	(53,107)
	$826,506	$744,160

(Thousands of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Inventories		
Materials and supplies	$244,099	$225,308
Fuel	183,249	189,485
Natural gas	169,835	161,745
	$597,183	$576,538

(Thousands of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Property, plant and equipment, net		
Electric plant	$33,203,139	$30,341,310
Natural gas plant	4,643,452	4,086,651
Common and other property	1,611,486	1,485,547
Plant to be retired [(a)]	71,534	101,279
CWIP	2,005,531	2,371,566
Total property, plant and equipment	41,535,142	38,386,353
Less accumulated depreciation	(13,168,418)	(12,608,305)
Nuclear fuel	2,347,422	2,186,799
Less accumulated amortization	(1,957,230)	(1,842,688)
	$28,756,916	$26,122,159

(a) As a result of the CPUC's 2010 approval of PSCo's CACJA compliance plan and the December 2013 approval of PSCo's preferred plans for applicable generating resources, PSCo has received approval for early retirement of Cherokee Unit 3 and Valmont Unit 5 between 2015 and 2017. 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, 2014
Borrowing limit	$2,750
Amount outstanding at period end	1,020
Average amount outstanding	802
Maximum amount outstanding	1,021

Weighted average interest rate, computed on a daily basis	0.36	%
Weighted average interest rate at period end	0.56	

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(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31 2014	2013	2012
Borrowing limit	$2,750	$2,450	$2,450
Amount outstanding at period end	1,020	759	602
Average amount outstanding	841	481	403
Maximum amount outstanding	1,200	1,160	634
Weighted average interest rate, computed on a daily basis	0.33 %	0.31 %	0.35 %
Weighted average interest rate at end of period	0.56	0.25	0.36

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, 2014 and 2013, there were $60.5 million and $47.8 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.

Amended Credit Agreements — In October 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an extension of maturity from July 2017 to October 2019. In addition, the borrowing limit for Xcel Energy Inc. has been increased to $1 billion from $800 million and the borrowing limit for SPS has been increased to $400 million from $300 million. As a result, the total borrowing limit under the amended credit agreements increased to $2.75 billion from $2.45 billion.

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.

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, 2014 and 2013, respectively, as evidenced by the table below:

	Debt-to-Total Capitalization Ratio 2014	2013
Xcel Energy	56 %	56 %
NSP-Wisconsin	48	47
NSP-Minnesota	48	47
SPS	47	49
PSCo	47	45

- 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.

- 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, 2014, 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.	$1,000.0	$380.5	$619.5
PSCo	700.0	388.4	311.6
NSP-Minnesota	500.0	166.1	333.9
SPS	400.0	67.0	333.0
NSP-Wisconsin	150.0	78.0	72.0
Total	$2,750.0	$1,080.0	$1,670.0

(a) These credit facilities have been amended to extend the maturity to 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, 2014 and 2013.

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)	
2015	$258
2016	656
2017	388
2018	1,206
2019	406

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

- In March 2014, PSCo issued $300 million of 4.3 percent first mortgage bonds due March 15, 2044;
- In May 2014, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June 2014, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June 2014, NSP-Wisconsin issued $100 million of 3.30 percent first mortgage bonds due June 15, 2024.

In connection with SPS' issuance of $150 million of 3.30 percent first mortgage bonds due June 15, 2024, SPS concurrently took certain actions to secure 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.

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.

During 2013, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In March 2013, PSCo issued $250 million of 2.50 percent first mortgage bonds due March 15, 2023 and $250 million of 3.95 percent first mortgage bonds due March 15, 2043.

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- In May 2013, Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016.
- In May 2013, NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023.
- In August 2013, SPS issued $100 million of 4.50 percent first mortgage bonds due Aug. 15, 2041. Including the $300 million of this series previously issued, total principal outstanding for this series is $400 million.

Issuances of Common Stock — 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 during the first six months of 2014. During the year ended Dec. 31, 2013, Xcel Energy Inc. issued approximately 7.7 million shares of common stock through this program and received cash proceeds of $222.7 million net of $2.7 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.

Debt Redemption — On May 31, 2013, Xcel Energy Inc. redeemed the entire $400 million principal amount of its 7.60 percent junior subordinated notes. Upon redemption, Xcel Energy Inc. recognized $6.3 million of related unamortized debt issuance costs as interest charges.

Deferred Financing Costs — Other assets included deferred financing costs of approximately $85 million and $83 million, net of amortization, at Dec. 31, 2014 and 2013, 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, 2014 and 2013, 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, 2014 and 2013, 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, 2014 and 2013 were 505,733,267 and 497,971,508, 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 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. 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 $1.6 billion and $1.4 billion in additional cash dividends to Xcel Energy Inc. at Dec. 31, 2014 and 2013, 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 47.1 percent and 57.5 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2014 and $848 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was $9.0 billion at Dec. 31, 2014, which did not exceed the limit of $9.5 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 52.8 percent at Dec. 31, 2014 and $8.3 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 53.6 percent at Dec. 31, 2014 and $396 million in retained earnings was not restricted.

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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 under the Federal Power Act. As of Dec. 31, 2014:

- PSCo has authorization to issue up to an additional $700 million of long-term debt and up to $800 million of short-term debt.
- SPS has authorization to issue up to $500 million of short-term debt and plans to file for additional long-term authorization.
- NSP-Wisconsin has authorization to issue up to $150 million of short-term debt and NSPW has filed for additional long-term debt authorization.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 47.1 percent and 57.5 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $9.5 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, 2014:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %	
NSP-Minnesota					
Electric Generation:					
Sherco Unit 3	$591,027	$376,322	$4,508	59.0	%
Sherco Common Facilities Units 1, 2 and 3	144,799	90,022	2	80.0	
Sherco Substation	4,790	2,978	—	59.0	
Electric Transmission:					
Grand Meadow Line and Substation	10,647	1,452	—	50.0	
CapX2020 Transmission	775,365	89,567	259,294	50.9	
Total NSP-Minnesota	$1,526,628	$560,341	$263,804		

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %	
NSP-Wisconsin					
Electric Transmission:					
CapX2020 Transmission	$26,434	$8,082	$103,940	80.7	%
La Crosse, Wis. to Madison, Wis.	—	—	9,814	50.0	
Total NSP-Wisconsin	$26,434	$8,082	$113,754		

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %	
PSCo					
Electric Generation:					
Hayden Unit 1	$98,145	$66,333	$1,405	75.5	%
Hayden Unit 2	121,571	59,999	8,867	37.4	
Hayden Common Facilities	37,049	16,928	135	53.1	
Craig Units 1 and 2	59,860	35,573	3,013	9.7	
Craig Common Facilities 1, 2 and 3	36,890	17,735	527	6.5	
Comanche Unit 3	883,971	81,748	64	66.7	
Comanche Common Facilities	23,624	1,051	308	82.0	

Electric Transmission:				
Transmission and other facilities, including substations	151,301	60,847	1,730	Various
Gas Transportation:				
Rifle, Colo. to Avon, Colo.	16,278	5,594	—	60.0
Total PSCo	$1,428,689	$345,808	$16,049	

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NSP-Minnesota and PSCo have approximately 500 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

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.

Prescription drug tax benefit — In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million of income tax benefit.

Medicare Part D — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to the federal subsidies during the first quarter of 2010.

Federal Tax Loss Carryback Claims — In 2012, 2013 and 2014, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013 and 2014 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 $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in March 2016. 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, 2014, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $12 million of income tax expense for the 2009 through 2011 claims, the recently filed 2013 claim, and the anticipated claim for 2014. At Dec. 31, 2014, the IRS has begun the Appeals process; however, the outcome and timing of a resolution is uncertain.

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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, 2014, 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	2010

In the first quarter of 2014, the state of Wisconsin commenced an examination of tax years 2009 through 2011. No material adjustments were proposed for those tax years. As of Dec. 31, 2014, 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, 2014	Dec. 31, 2013
Unrecognized tax benefit — Permanent tax positions	$16.2	$12.9
Unrecognized tax benefit — Temporary tax positions	50.3	28.3
Total unrecognized tax benefit	$66.5	$41.2

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2014	2013	2012
Balance at Jan. 1	$41.2	$34.5	$34.7
Additions based on tax positions related to the current year	28.7	15.1	5.2
Reductions based on tax positions related to the current year	(2.0)	(0.4)	(5.7)
Additions for tax positions of prior years	16.0	21.6	9.6
Reductions for tax positions of prior years	(6.0)	(4.8)	(9.3)
Settlements with taxing authorities	(9.6)	(24.8)	—
Lapse of applicable statutes of limitations	(1.8)	—	—
Balance at Dec. 31	$66.5	$41.2	$34.5

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, 2014	Dec. 31, 2013
NOL and tax credit carryforwards	$(28.5)	$(27.1)

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 process progresses and state audits resume. As the IRS Appeals process moves closer to completion and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $10 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, 2014, 2013 and 2012 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2014, 2013 or 2012.

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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)	2014	2013
Federal NOL carryforward	$1,349	$1,311
Federal tax credit carryforwards	327	294
State NOL carryforwards	1,722	1,706
Valuation allowances for state NOL carryforwards	(53)	(51)
State tax credit carryforwards, net of federal detriment [a]	19	17

(a) State tax credit carryforwards are net of federal detriment of $10 million and $9 million as of Dec. 31, 2014 and 2013.

The federal carryforward periods expire between 2021 and 2034. The state carryforward periods expire between 2016 and 2034.

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:

	2014	2013	2012
Federal statutory rate	35.0 %	35.0 %	35.0 %
Increases (decreases) in tax from:			
Tax credits recognized, net of federal income tax expense	(2.6)	(2.6)	(2.2)
Regulatory differences — utility plant items	(1.3)	(1.6)	(1.0)
NOL carryback	(0.9)	(0.8)	(1.1)
State income taxes, net of federal income tax benefit	4.0	4.1	4.0
Change in unrecognized tax benefits	0.2	0.6	—
Prescription drug tax benefit and Medicare Part D	—	—	(1.2)
Other, net	(0.5)	(0.9)	(0.3)
Effective income tax rate	33.9 %	33.8 %	33.2 %

The components of Xcel Energy’s income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2014	2013	2012
Current federal tax (benefit) expense	$(73,160)	$(46,173)	$7,876
Current state tax expense	9,225	7,678	31,478
Current change in unrecognized tax expense (benefit)	23,915	13,162	(1,704)
Deferred federal tax expense	505,236	439,085	366,409
Deferred state tax expense	84,787	80,907	50,741
Deferred change in unrecognized tax (benefit) expense	(20,645)	(4,930)	2,013
Deferred investment tax credits	(5,543)	(5,753)	(6,610)
Total income tax expense	$523,815	$483,976	$450,203

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2014	2013	2012
Deferred tax expense excluding items below	$616,934	$588,053	$559,860
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(48,674)	(64,420)	(63,862)
Tax benefit (expense) allocated to OCI	1,117	(8,572)	12,102
Other	1	1	(6)
Deferred tax expense	$569,378	$515,062	$508,094

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The components of Xcel Energy's net deferred tax liability (current and noncurrent) at Dec. 31 were as follows:

(Thousands of Dollars)	2014	2013
Deferred tax liabilities:		
Differences between book and tax bases of property	$6,257,191	$5,562,446
Regulatory assets	300,762	321,636
Other	300,251	254,639
Total deferred tax liabilities	$6,858,204	$6,138,721
Deferred tax assets:		
NOL carryforward	$552,274	$532,774
Tax credit carryforward	346,064	311,388
Rate refund	93,956	49,804
Unbilled revenue - fuel costs	55,021	58,908
Regulatory liabilities	49,712	40,947
Environmental remediation	42,716	42,886
Deferred investment tax credits	31,886	34,231
NOL and tax credit valuation allowances	(3,402)	(3,263)
Other	83,199	81,202
Total deferred tax assets	$1,251,426	$1,148,877
Net deferred tax liability	$5,606,778	$4,989,844

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 substantially all 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.

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:

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- 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.

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The dilutive impact of common stock equivalents affecting EPS was as follows:

	2014			2013			2012		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$1,021,306			$948,234			$905,229		
Basic EPS:									
Earnings available to common shareholders	1,021,306	503,847	$ 2.03	948,234	496,073	$ 1.91	905,229	487,899	$ 1.86
Effect of dilutive securities:									
Equity awards	—	270		—	459		—	535	
Diluted EPS:									
Earnings available to common shareholders	$1,021,306	504,117	$ 2.03	$948,234	496,532	$ 1.91	$905,229	488,434	$ 1.85

Share Repurchase — In February 2012, Xcel Energy Inc.'s Board of Directors approved the repurchase of up to 0.7 million shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. In March 2012, Xcel Energy Inc. repurchased the approved 0.7 million shares in the open market at an average price of $26.42 per share. In addition, approximately 0.9 million shares of common stock were purchased in February 2012 through an agent independent of Xcel Energy to fulfill requirements for the employer match pursuant to the Xcel Energy 401(k) Savings Plan; the NCE Employees' Savings and Stock Ownership Plan for Bargaining Unit Employees and Former Non-Bargaining Unit Employees; and the NCE Employee Investment Plan for Bargaining Unit Employees and Non-Bargaining Employees.

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)	2014	2013	2012
Granted shares	46	33	33
Grant date fair value	$29.69	$28.30	$26.43

A summary of the changes of nonvested restricted stock for the year ended 2014 were as follows:

(Shares in Thousands)	Shares		Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2014	62		$27.33
Granted	46		29.69
Vested	(29	)	26.67
Dividend equivalents	3		30.94
Nonvested restricted stock at Dec. 31, 2014	82		29.00

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). The plan allows 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.

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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 shares, a total of 0.4 million and 0.2 million time-based equity shares subject only to service conditions were granted in 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 units awarded in 2014 are based on relative TSR, measured identically to TSR liability awards granted in 2014, 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 2011 to 2014, 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 grants, depending on the level of achievement.

- The 2010 awards measured on EPS growth met their targets as of Dec. 31, 2011, and were settled in shares in February 2012.
- 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 will be settled in shares in February 2015.

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)	2014	2013	2012
Granted units	588	774	591
Weighted average grant date fair value	$29.90	$27.65	$27.35

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. Approximately 0.1 million of these units vested during 2012 at a total fair value of $1.2 million.

A summary of the changes in the nonvested portion of these equity award units for the year ended 2014, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2014	1,312	$27.53
Granted	588	29.90
Forfeited	(99)	28.36
Vested	(546)	27.34
Dividend equivalents	67	28.04
Nonvested Units at Dec. 31, 2014	1,322	28.63

The total fair value of these nonvested equity awards as of Dec. 31, 2014 was $47.5 million and the weighted average remaining contractual life was 1.6 years.

Stock Equivalent Unit Plan — 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 after the member has been elected to the Board. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash, and similarly have no further service or other conditions attached. Dividends on Xcel Energy 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.

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The stock equivalent units granted for the years ended Dec. 31 were as follows:

(Units in Thousands)	2014	2013	2012
Granted units	62	69	65
Grant date fair value	$30.57	$29.52	$27.41

A summary of the stock equivalent unit changes for the year ended 2014 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2014	636	$22.98
Granted	62	30.57
Units distributed	(33)	21.09
Dividend equivalents	25	30.80
Stock equivalent units at Dec. 31, 2014	690	24.03

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 2014 and 2013 awards, Xcel Energy Inc.'s TSR is compared to the TSR of other companies in a 23-member utilities peer group. For 2012 awards, TSR is compared to the EEI Investor-Owned Electrics Index. 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)	2014	2013	2012
Awards granted	270	215	161

The total amounts of TSR liability awards settled during the years ended Dec. 31 were as follows:

(In Thousands)	2014	2013	2012
Awards settled	—	108	286
Settlement amount (cash and common stock)	$—	$3,057	$7,554

The amount of cash used to settle Xcel Energy's TSR liability awards was $1.5 million and $3.8 million in 2013 and 2012, respectively.

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 0.4 million and 0.2 million of equity awards were granted in 2014 and 2013, respectively, with vesting subject only to service conditions for periods up to five years. All of these instruments are considered to be equity awards, generally 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.

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The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2014	2013	2012
Compensation cost for share-based awards [(a) (b) (c)]	$32,189	$24,613	$26,970
Tax benefit recognized in income	12,557	9,571	10,513
Capitalized compensation cost for share-based awards	1,887	1,698	4,270

(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, $7.0 million, and $22.2 million for the years ended 2014, 2013 and 2012, respectively.

(c) 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.

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, 2014 and 2013, there was approximately $27.8 million and $22.1 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, 2014 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 48 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2014:

- NSP-Minnesota had 2,011 and NSP-Wisconsin had 402 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 272 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates in 2015 and 2016.
- PSCo had 2,063 bargaining employees covered under a collective-bargaining agreement, which expired in May 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.
- SPS had 840 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, 2014 and 2013 were $46.5 million and $36.5 million, respectively. In 2014 and 2013, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $4.7 million and $6.6 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 2014 were above the assumed level of 7.05 percent;
- Investment returns in 2013 were below the assumed level of 6.88 percent;
- Investment returns in 2012 were above the assumed level of 7.10 percent; and

In 2015, Xcel Energy's expected investment return assumption is 7.09 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.

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The following table presents the target pension asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2014	2013
Domestic and international equity securities	37 %	30 %
Long-duration fixed income and interest rate swap securities	27	33
Short-to-intermediate fixed income securities	13	15
Alternative investments	21	20
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, 2014 and 2013:

	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

	Dec. 31, 2013			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$109,700	$—	$—	$109,700
Derivatives	—	29,759	—	29,759
Government securities	—	230,212	—	230,212
Corporate bonds	—	547,715	—	547,715
Asset-backed securities	—	6,754	—	6,754
Mortgage-backed securities	—	15,025	—	15,025
Common stock	99,346	—	—	99,346
Private equity investments	—	—	152,849	152,849
Commingled funds	—	1,769,076	—	1,769,076
Real estate	—	—	47,553	47,553
Securities lending collateral obligation and other	—	2,151	—	2,151
Total	$209,046	$2,600,692	$200,402	$3,010,140

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The following tables present the changes in Xcel Energy's Level 3 pension plan assets for the years ended Dec. 31, 2014, 2013 and 2012:

(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.

(Thousands of Dollars)	Jan. 1, 2012	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2012
Asset-backed securities	$31,368	$3,886	$(5,363)	$(15,252)	$—	$14,639
Mortgage-backed securities	73,522	1,822	(2,127)	(33,313)	—	39,904
Private equity investments	159,363	17,537	(22,587)	4,185	—	158,498
Real estate	37,106	19	6,048	21,424	—	64,597
Total	$301,359	$23,264	$(24,029)	$(22,956)	$—	$277,638

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)	2014	2013
Accumulated Benefit Obligation at Dec. 31	$3,545,928	$3,282,651
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$3,440,704	$3,639,530
Service cost	88,342	96,282
Interest cost	156,619	140,690
Plan amendments	—	(4,120)
Actuarial loss (gain)	342,826	(153,338)
Benefit payments	(281,739)	(278,340)
Obligation at Dec. 31	$3,746,752	$3,440,704

(Thousands of Dollars)	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$3,010,140	$2,943,783
Actual return on plan assets	224,808	152,259
Employer contributions	130,562	192,438

Benefit payments	(281,739)	(278,340)
Fair value of plan assets at Dec. 31	$3,083,771	$3,010,140

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(Thousands of Dollars)	2014	2013
Funded Status of Plans at Dec. 31:		
Funded status [a]	$(662,981)	$(430,564)

[a] Amounts are recognized in noncurrent liabilities on Xcel Energy’s consolidated balance sheets.

(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$1,757,935	$1,549,474
Prior service credit	(10,878)	(12,624)
Total	$1,747,057	$1,536,850

(Thousands of Dollars)	2014	2013
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	$113,432	$125,702
Noncurrent regulatory assets	1,558,649	1,343,432
Deferred income taxes	29,143	26,403
Net-of-tax accumulated OCI	45,833	41,313
Total	$1,747,057	$1,536,850
Measurement date	Dec. 31, 2014	Dec. 31, 2013

	2014	2013
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.11 %	4.75 %
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP 2014	RP 2000

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.

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 2012 through 2015 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy’s pension plans were as follows:

- $90.0 million in January 2015;
- $130.6 million in 2014;
- $192.4 million in 2013; and
- $198.1 million in 2012.

For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments — In 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.

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Benefit Costs — The components of Xcel Energy’s net periodic pension cost were:

(Thousands of Dollars)	2014	2013	2012
Service cost	$88,342	$96,282	$86,364
Interest cost	156,619	140,690	157,035
Expected return on plan assets	(207,205)	(198,452)	(207,095)
Amortization of prior service (credit) cost	(1,746)	5,871	21,065
Amortization of net loss	116,762	144,151	108,982
Net periodic pension cost	152,772	188,542	166,351
Costs not recognized due to effects of regulation	(26,315)	(36,724)	(39,217)
Net benefit cost recognized for financial reporting	$126,457	$151,818	$127,134

	2014	2013	2012
Significant Assumptions Used to Measure Costs:			
Discount rate	4.75 %	4.00 %	5.00 %
Expected average long-term increase in compensation level	3.75	3.75	4.00
Expected average long-term rate of return on assets	7.05	6.88	7.10

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 2015 pension cost calculations is 7.09 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 $32.4 million in 2014, $30.3 million in 2013 and $28.0 million in 2012.

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.

- The former NSP, which includes 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 former NCE, which includes 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.

In 1993, Xcel Energy adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized APBO on a straight-line basis over 20 years.

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.

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The following table presents the target postretirement asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2014	2013
Domestic and international equity securities	25 %	41 %
Short-to-intermediate fixed income securities	57	40
Alternative investments	13	13
Cash	5	6
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, 2014 and 2013:

	Dec. 31, 2014			
(Thousands of Dollars)	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

	Dec. 31, 2013			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents [a]	$20,438	$—	$—	$20,438
Derivatives	—	(414)	—	(414)
Government securities	—	58,421	—	58,421
Insurance contracts	—	52,808	—	52,808
Corporate bonds	—	51,861	—	51,861
Asset-backed securities	—	3,358	—	3,358
Mortgage-backed securities	—	24,246	—	24,246
Commingled funds	—	298,258	—	298,258
Other	—	(16,940)	—	(16,940)
Total	$20,438	$471,598	$—	$492,036

[a] Includes restricted cash of $1.0 million and $0.7 million at Dec. 31, 2014 and 2013, respectively.

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For the year ended Dec. 31, 2014 there were no assets transferred in or out of Level 3. The following tables present the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the years ended Dec. 31, 2013 and 2012:

(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	$757	$—	$—	$—	$(757)	$—
Mortgage-backed securities	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.

(Thousands of Dollars)	Jan. 1, 2012	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2012
Asset-backed securities	$7,867	$(331)	$1,481	$(8,260)	$—	$757
Mortgage-backed securities	27,253	(724)	3,301	10,128	—	39,958
Private equity investments	479	—	(65)	(414)	—	—
Real estate	144	—	35	(179)	—	—
Total	$35,743	$(1,055)	$4,752	$1,275	$—	$40,715

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)	2014	2013
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$731,428	$851,952
Service cost	3,457	4,079
Interest cost	34,028	32,141
Medicare subsidy reimbursements	1,861	1,197
Plan amendments	—	(14,571)
Plan participants' contributions	7,148	9,580
Actuarial gain	(81,699)	(103,359)
Benefit payments	(53,354)	(49,591)
Obligation at Dec. 31	$642,869	$731,428

(Thousands of Dollars)	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$492,036	$480,842
Actual return on plan assets	12,083	33,644
Plan participants' contributions	7,148	9,580
Employer contributions	17,145	17,561
Benefit payments	(53,354)	(49,591)
Fair value of plan assets at Dec. 31	$475,058	$492,036

(Thousands of Dollars)	2014	2013
Funded Status of Plans at Dec. 31:		
Funded status	$(167,811)	$(239,392)
Noncurrent assets	1,014	—
Current liabilities	(9,110)	(6,807)
Noncurrent liabilities	(159,715)	(232,585)

Net postretirement amounts recognized on consolidated balance sheets	$(167,811)	$(239,392)

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(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$124,064	$195,630
Prior service credit	(75,610)	(86,298)
Transition obligation	—	2
Total	$48,454	$109,334

(Thousands of Dollars)	2014	2013
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	$285	$12,102
Noncurrent regulatory assets	59,697	99,071
Current regulatory liabilities	(892)	(319)
Noncurrent regulatory liabilities	(17,216)	(8,858)
Deferred income taxes	2,559	2,965
Net-of-tax accumulated OCI	4,021	4,373
Total	$48,454	$109,334
Measurement date	Dec. 31, 2014	Dec. 31, 2013

	2014	2013
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.08 %	4.82 %
Mortality table	RP 2014	RP 2000
Health care costs trend rate — initial	6.50 %	7.00 %

Effective Jan. 1, 2015, the initial medical trend rate was decreased from 7.0 percent to 6.5 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is four 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	$66,034	$(55,588)
Service and interest components	4,432	(3,640)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy contributed $17.1 million during 2014, $17.6 million during 2013, $47.1 million during 2012 and expects to contribute approximately $12.8 million during 2015.

Plan Amendments — In 2014, there were no plan amendments made which affected the benefit obligation. The 2013 decrease of the projected Xcel Energy and PSCo postretirement health and welfare benefit obligation for plan amendments is due to changes in the participant co-pay structure for certain retiree groups.

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Benefit Costs — The components of Xcel Energy's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2014	2013	2012
Service cost	$3,457	$4,079	$4,203
Interest cost	34,028	32,141	37,861
Expected return on plan assets	(33,954)	(33,011)	(28,409)
Amortization of transition obligation	—	825	14,320
Amortization of prior service credit	(10,688)	(12,501)	(7,552)
Amortization of net loss	11,740	22,325	16,906
Net periodic postretirement benefit cost	4,583	13,858	37,329
Additional cost recognized due to effects of regulation	—	—	3,891
Net benefit cost recognized for financial reporting	$4,583	$13,858	$41,220

	2014	2013	2012
Significant Assumptions Used to Measure Costs:			
Discount rate	4.82 %	4.10 %	5.00 %
Expected average long-term rate of return on assets	7.17	7.11	6.75

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
2015	$247,479	$48,398	$2,670	$45,728
2016	269,953	48,665	2,836	45,829
2017	260,182	48,519	3,005	45,514
2018	267,406	48,977	3,170	45,807
2019	269,809	48,461	3,327	45,134
2020-2024	1,352,192	230,692	18,721	211,971

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.

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Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2014, 2013 and 2012. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 1,000 in 2014 from approximately 1,100 in 2013. 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)	2014	2013	2012
Multiemployer pension contributions:			
NSP-Minnesota	$20,254	$23,515	$14,984
NSP-Wisconsin	156	130	163
Total	$20,410	$23,645	$15,147
Multiemployer other postretirement benefit contributions:			
NSP-Minnesota	$273	$390	$197
Total	$273	$390	$197

10. Other Income, Net

Other income, net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2014	2013	2012
Interest income	$7,353	$8,343	$10,327
Other nonoperating income	4,866	3,025	3,483
Insurance policy expense	(6,923)	(8,292)	(7,365)
Other nonoperating expense	—	(104)	(270)
Other income, net	$5,296	$2,972	$6,175

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.

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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 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.

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 purchased from MISO, PJM, ERCOT, SPP and NYISO, generally referred to as FTRs. Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from an 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 the FCA 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 uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

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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 $312.1 million and $240.3 million at Dec. 31, 2014 and 2013, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $74.1 million and $58.5 million at Dec. 31, 2014 and 2013, 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, 2014 and 2013:

	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.

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	Dec. 31, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$33,281	$33,281	$—	$—	$33,281
Commingled funds	457,986	—	452,227	—	452,227
International equity funds	78,812	—	81,671	—	81,671
Private equity investments	52,143	—	—	62,696	62,696
Real estate	45,564	—	—	57,368	57,368
Debt securities:					
Government securities	34,304	—	27,628	—	27,628
U.S. corporate bonds	80,275	—	83,538	—	83,538
International corporate bonds	15,025	—	15,358	—	15,358
Municipal bonds	241,112	—	232,016	—	232,016
Equity securities:					
Common stock	406,695	581,243	—	—	581,243
Total	$1,445,197	$614,524	$892,438	$120,064	$1,627,026

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $87.1 million of equity investments in unconsolidated subsidiaries and $41.9 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(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

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3	Dec. 31, 2012
Private equity investments	$9,203	$20,671	$(1,931)	$5,307	$—	$33,250
Real estate	26,395	9,777	(3,611)	6,513	—	39,074
Asset-backed securities	16,501	—	(14,450)	16	—	2,067
Mortgage-backed securities	78,664	33,016	(79,899)	(1,572)	—	30,209
Total	$130,763	$63,464	$(99,891)	$10,264	$—	$104,600

(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.

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The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2014:

(Thousands of Dollars)	Final Contractual Maturity 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	$—	$—	$—	$28,808	$28,808
U.S. corporate bonds	300	15,530	62,838	(1,106)	77,562
International corporate bonds	—	4,212	12,129	—	16,341
Municipal bonds	1,893	35,048	41,530	170,730	249,201
Asset-backed securities	—	—	6,389	2,861	9,250
Mortgage-backed securities	—	—	—	23,895	23,895
Debt securities	$2,193	$54,790	$122,886	$225,188	$405,057

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, 2014, accumulated other comprehensive losses related to interest rate derivatives included $2.8 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, 2014, 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, 2014 and 2013.

At Dec. 31, 2014, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 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.

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The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) [(a)(b)]	2014	2013
MWh of electricity	56,361	58,423
MMBtu of natural gas	927	9,854
Gallons of vehicle fuel	282	482

(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, 2014, four of Xcel Energy's 10 most significant counterparties for these activities, comprising $56.2 million or 23 percent of this credit exposure, had investment grade credit ratings from S&P's, Moody's or Fitch Ratings. The remaining six most significant counterparties, comprising $65.6 million or 27 percent of this credit exposure at Dec. 31, 2014, were not rated by these agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. All 10 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)	2014	2013	2012
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(59,753)	$(61,241)	$(45,738)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	(163)	12	(19,200)
After-tax net realized losses on derivative transactions reclassified into earnings	2,288	1,476	3,697
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$(57,628)	$(59,753)	$(61,241)

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The following tables detail the impact of derivative activity during the years ended Dec. 31, 2014, 2013 and 2012, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	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:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
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:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
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

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	Year Ended Dec. 31, 2012				
	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	$(31,913)	$—	$6,582 [a]	$ —	$—
Vehicle fuel and other commodity	120	—	(198) [b]	—	—
Total	$(31,793)	$—	$6,384	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$12,226 [c]
Electric commodity	—	44,162	—	(39,999) [d]	—
Natural gas commodity	—	(10,809)	—	80,902 [e]	(137) [d]
Total	$—	$33,353	$—	$ 40,903	$12,089

[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, 2012 included $5.0 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, 2014, 2013 and 2012 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, 2014, 2013 and 2012. 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, 2014, there were no derivative instruments with contract provisions that required the posting of collateral or settlement of the contracts. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, derivative instruments reflected in a $1.4 million gross liability position on the consolidated balance sheets at Dec. 31, 2013, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $1.4 million at Dec. 31, 2013. At Dec. 31, 2013, there was no collateral posted on these specific contracts.

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, 2014 and 2013.

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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, 2014:

	Dec. 31, 2014					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	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

	Dec. 31, 2014					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	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.

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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, 2013:

	Dec. 31, 2013					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$88	$—	$88	$ —	$88
Other derivative instruments:						
Commodity trading	—	20,610	1,167	21,777	(7,994)	13,783
Electric commodity	—	—	47,112	47,112	(8,210)	38,902
Natural gas commodity	—	5,906	—	5,906	—	5,906
Total current derivative assets	$—	$26,604	$48,279	$74,883	$ (16,204)	58,679
PPAs [a]						33,028
Current derivative instruments						$91,707
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$29	$—	$29	$ (16)	$13
Other derivative instruments:						
Commodity trading	—	32,074	3,395	35,469	(9,071)	26,398
Total noncurrent derivative assets	$—	$32,103	$3,395	$35,498	$ (9,087)	26,411
PPAs [a]						58,431
Noncurrent derivative instruments						$84,842

	Dec. 31, 2013					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$10,546	$1,804	$12,350	$ (12,002)	$348
Electric commodity	—	—	8,210	8,210	(8,210)	—
Total current derivative liabilities	$—	$10,546	$10,014	$20,560	$ (20,212)	348
PPAs [a]						23,034
Current derivative instruments						$23,382
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$14,382	$—	$14,382	$ (9,087)	$5,295
Total noncurrent derivative liabilities	$—	$14,382	$—	$14,382	$ (9,087)	5,295
PPAs [a]						203,929
Noncurrent derivative instruments						$209,224

(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, 2013. At Dec. 31, 2013, derivative assets and liabilities include obligations to return cash collateral of $0.2 million and rights to reclaim cash collateral of $4.2 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.

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The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2014, 2013 and 2012:

	Year Ended Dec. 31		
(Thousands of Dollars)	2014	2013	2012
Balance at Jan. 1	$41,660	$16,649	$12,417
Purchases	135,008	61,474	37,595
Settlements	(145,974)	(45,199)	(44,950)
Transfers out of Level 3	(1,093)	—	—
Net transactions recorded during the period:			
Gains recognized in earnings [(a)]	10,692	3,947	463
Gains recognized as regulatory liabilities	15,862	4,789	11,124
Balance at Dec. 31	$56,155	$41,660	$16,649

(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. 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. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2013 and 2012.

Fair Value of Long-Term Debt

As of Dec. 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	2014		2013	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,757,360	$13,360,236	$11,191,517	$11,878,643

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, 2014 and 2013, 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 is based on a requested 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 includes a proposed rate moderation plan for 2014 and 2015.

NSP-Minnesota’s moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve and the use of expected funds from the DOE for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota’s decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello LCM/EPU project costs and NSP-Minnesota's request to amortize amounts associated with the canceled PI EPU project.

In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

In August 2014, NSP-Minnesota revised its requested rate increase to $142.2 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $248.2 million.

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In December 2014, the ALJ issued her recommendations in the NSP-Minnesota electric rate case. While the report did not quantify the overall rate increases, NSP-Minnesota estimates that her recommendations would result in a rate increase of $69.1 million in 2014 and an incremental rate increase of $122.4 million in 2015. In addition, she recommended an ROE of 9.77 percent and an equity ratio of 52.5 percent.

The following table summarizes the estimated impact of the ALJ's recommendation, DOC's previously filed surrebuttal testimony and NSP-Minnesota's revised request and includes certain estimated adjustments:

2014 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$192.7	$192.7	$ 192.7
Sales forecast (true-up to 12 months of actual weather-normalized sales)	(15.8)	(43.2)	(15.8)
ROE	(28.4)	(36.2)	—
Monticello EPU cost recovery	(31.3)	(33.9)	—
Monticello EPU depreciation deferral	—	—	(12.2)
Property taxes	(9.0)	(9.0)	(9.0)
PI EPU cost recovery	(5.1)	(5.1)	(5.1)
Health care, pension and other benefits	(1.9)	(11.4)	(1.9)
Other, net	(5.2)	(8.0)	(6.5)
Total recommendation 2014 — unadjusted	$96.0	$45.9	$ 142.2
Estimated true-up adjustments:			
Sales forecast [a]	$(22.7)	$4.7	$ (22.7)
Property taxes [b]	(4.2)	(4.2)	(4.2)
Total recommendation 2014 — adjusted	$69.1	$46.4	$ 115.3
2015 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$98.5	$98.5	$ 98.5
Monticello EPU cost recovery	29.1	29.1	—
Monticello EPU cost disallowance [c]	—	(10.2)	—
Excess depreciation reserve adjustment [d]	—	(22.7)	—
Depreciation	—	(17.5)	—
Monticello EPU depreciation deferral	—	—	1.6
Monticello EPU step increase	—	—	10.1
Property taxes	(3.3)	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)	(11.1)
DOE settlement proceeds	10.1	10.1	10.1
Emission chemicals	(1.6)	(1.6)	(1.6)
Other, net	0.7	(4.8)	1.7
Total recommendation 2015 step increase	$122.4	$66.5	$ 106.0
Unadjusted cumulative total for 2014 and 2015 step increase	$218.4	$112.4	$ 248.2
Estimated adjusted cumulative total for 2014 and 2015 step increase	$191.5	$112.9	$ 221.3

[a] The true-up adjustment for the sales forecast reflects weather-normalized sales through December 2014.

[b] The true-up adjustment for property taxes reflects NSP-Minnesota's 2014 year end property tax accruals.

[c] In July 2014, the DOC recommended a cost disallowance of approximately $71.5 million on a Minnesota jurisdictional basis which equates to a total NSP System disallowance of approximately $94 million. This would reduce NSP-Minnesota's revenue requirement by approximately $10.2 million in 2015.

[d] Adjustment is due to timing differences and/or methodology of accelerating amortization of the excess depreciation reserve over three years.

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The ALJ recommended no recovery of the Monticello EPU project costs in 2014, accepting the DOC's argument that the EPU portion was not used and useful in 2014 and should be treated as a 2015 step project. NSP-Minnesota fully met the NRC's requirements for the EPU as of Dec. 31, 2014. NSP-Minnesota is currently executing the power ascension plan consistent with the NRC license amendment approval and as of Dec. 31, 2014 had operated the plant using 56 MW of the additional 71 MW from the EPU. The full 71 MW of additional EPU output is expected to be attained in the first half of 2015. Although the final NRC requirements have been met, rate recovery is still subject to true-up. The ALJ recommendation does not reflect any potential adjustments for the pending Monticello prudence review.

The ALJ did not make a recommendation on the use of the surplus depreciation reserve in NSP-Minnesota's rate moderation proposal. The table above reflects NSP-Minnesota's filed position for the use of the proposed amortization of the surplus depreciation reserve.

The ALJ also recommended adoption of a full decoupling pilot for the residential and small C&I classes, based on actual sales, effective the month after the MPUC issues its final order in 2015. Full decoupling would eliminate the impact of weather variability on electric sales for the residential and small C&I classes for NSP-Minnesota.

NSP-Minnesota has also filed a plan for any potential refund that treats the multi-year case as a single period. In January 2015, the DOC recommended an alternative option that views each year of the multi-year case separately, which would result in lower 2015 revenues.

A current regulatory liability representing NSP-Minnesota's best estimate of a refund obligation for 2014 associated with interim rates was recorded as of Dec. 31, 2014. The estimated amount is generally consistent with the ALJ recommendation.

The MPUC is expected to deliberate on March 26, 2015 and a final order is anticipated in the second quarter of 2015.

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. 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.

NSP-Minnesota filed a report to support the prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional NRC licensing related requests over the five-plus year application process.

The cost deviation is in line with similar nuclear upgrade projects undertaken by other utilities. In addition, the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and as of Dec. 31, 2014, has fully complied with the NRC's license requirements for higher power levels.

In July 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis.

In August 2014, the OAG filed rebuttal testimony and recommended a disallowance of recovery of $321 million for the entire NSP System (based on a total capitalized cost of $748 million), and no return on $107 million. NSP-Minnesota believes the costs of the project were prudent and its decisions and actions do not warrant a disallowance.

In February 2015, an ALJ issued his report finding that NSP-Minnesota was imprudent in managing the project. Consistent with the DOC's position, the ALJ proposed: (1) 85 percent of the project cost be assigned to EPU costs and applied the DOC's cost-effectiveness test; and (2) disallowance of recovery of approximately $71.5 million of EPU costs, resulting in a reduction of $10.24 million to the 2015 revenue requirement on a Minnesota jurisdictional basis. This would equate to a total NSP System disallowance of approximately $94 million if the MPUC and other state commissions accepted this recommendation. NSP-Minnesota plans to file exceptions to the ALJ's report with the MPUC.

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On Feb. 12, 2015, NSP-Minnesota, Xcel Large Industrials and the OAG filed exceptions to the ALJ's Report, advocating their initial positions. On Feb. 17, 2015, reply comments were filed by various parties, including NSP-Minnesota. Oral arguments are scheduled to be held on March 3, 2015.

NSP-Minnesota does not expect a delay to the scheduled proceedings and a final MPUC order is anticipated in the second quarter of 2015. The MPUC decision for the Monticello prudence review is expected to be reflected in the final results of NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

NSP-Minnesota – 2015 Transmission Cost Recovery Rate Filing — In October 2014, the 2015 NSP-Minnesota TCR filing was filed with the MPUC, requesting recovery of $65.8 million of 2015 transmission investment costs not previously included in electric base rates. An MPUC decision is anticipated in the second quarter of 2015, with implementation of new rates soon after approval.

PI Nuclear Plant EPU — In 2009, the MPUC granted NSP-Minnesota a CON for an EPU project at the PI nuclear generating plant. The total estimated cost of the EPU was $294 million, of which approximately $78.9 million had been incurred through 2012, including AFUDC of approximately $12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

NSP-Minnesota plans to address recovery of incurred costs in rate cases for each of the NSP-Minnesota jurisdictions. As noted, NSP-Minnesota is seeking recovery in Minnesota in its pending Minnesota 2014 Multi-Year electric rate case. In December 2014, NSP-Minnesota filed a request with the FERC for approval to recover a portion of the costs from NSP-Wisconsin through the Interchange Agreement commencing Jan. 1, 2016. The request is pending FERC action. NSP-Wisconsin plans to seek cost recovery in future rate cases. Based on the outcome of the December 2012 MPUC decision, EPU costs incurred to date were compared to the discounted value of the estimated future rate recovery based on past jurisdictional precedent, resulting in a $10.1 million pretax charge in December 2012 which is included in O&M expense for that year. The remaining PI EPU costs were deferred for future amortization corresponding with rate recovery in various NSP jurisdictions.

Pending Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 HTY adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of $433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately $9.0 million for certain TCR rider and Infrastructure rider projects to base rates.

Interim rates of $15.6 million, subject to refund, went into effect in January 2015. At this time, the case is in the discovery phase and further procedure scheduling may be established, as necessary during the first quarter of 2015. Final rates are anticipated to be effective mid-2015.

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. Based on the approved savings goals, the estimated average annual electric and natural gas incentives are $30.6 million and $3.6 million, respectively.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In December 2014, the MPUC approved NSP-Minnesota's 2013 CIP electric and natural gas financial incentives totaling $42.7 million and $5.4 million, respectively.
- In addition, the MPUC approved NSP-Minnesota's proposed 2014 to 2015 electric and natural gas CIP riders. NSP-Minnesota estimates 2015 recovery of $15.5 million of electric CIP expenses and $6.0 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.

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NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In August 2014, NSP-Minnesota filed a 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 $14.9 million from Minnesota gas utility customers beginning Jan. 1, 2015, including $4.8 million of deferred sewer separation and integrity management costs which is the 2015 portion of a five year amortization. In December 2014, the MPUC approved the GUIC rider for $14.7 million, with an effective date of Feb. 1, 2015.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

NSP-Wisconsin – Wisconsin 2015 Electric Rate Case — In May 2014, NSP-Wisconsin filed a request with the PSCW to increase electric rates by $20.6 million, or 3.2 percent, effective Jan. 1, 2015. The request was for the limited purpose of updating 2015 electric rates to reflect anticipated increases in the production and transmission fixed charges and the fuel and purchased power components of the interchange agreement with NSP-Minnesota. No changes were requested to the capital structure or the 10.2 percent ROE authorized by the PSCW in the 2014 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap for 2015 only, in which 100 percent of the earnings above the authorized ROE would be refunded to customers.

In December 2014, the PSCW issued its order approving an overall increase in NSP-Wisconsin's electric rates of approximately $14.2 million, or 2.2 percent, reflecting the updated November forecast for fuel and purchased power costs. The PSCW order was consistent with the agreement reached by the parties, as described above. The new rates were effective Jan. 1, 2015.

Pending Regulatory Proceedings — FERC

MISO ROE Complaint/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE applicable to 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.

In June 2014, the FERC issued an order in a different ROE proceeding adopting a new ROE methodology for electric utilities. The new ROE methodology requires electric utilities to use a two-step discounted cash flow analysis to estimate cost of equity that incorporates both short-term and long-term growth projections.

In October 2014, the FERC upheld the determination of the long-term growth rate to be used together with a short-term growth rate in its new ROE methodology. The FERC separately set the ROE complaint against the MISO transmission owners for settlement judge and hearing procedures. The FERC directed parties to apply the new ROE methodology, but denied the complaints related to equity capital structures and ROE adders. The FERC established a Nov. 12, 2013 refund effective date. The settlement judge procedures were unsuccessful. FERC action is pending. In January 2015, the ROE complaint was set for full hearing procedures, with an ALJ initial decision to be issued by November 2015 and a FERC order issued no earlier than 2016.

In November 2014, the MISO transmission owners filed a request for FERC approval of a 50 basis point RTO membership ROE adder, with collection deferred until resolution of the ROE complaint. In January 2015, the FERC approved the ROE adder, 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. In 2015, several intervenors sought rehearing of the commission order.

In February 2015, a separate group of customers filed an additional complaint proposing to reduce the MISO region ROE to 8.67 percent, prior to any 50 basis point RTO adder, with a refund effective date of Feb. 12, 2015. Answers to the complaint are to be filed by March 2015.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE as of Dec. 31, 2014. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between \$5 million and \$7 million annually for the NSP System.

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PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2014 Electric Rate Case — In 2014, PSCo filed an electric rate case with the CPUC requesting an increase in annual revenue of approximately $136.0 million, or 4.83 percent. The requested 2015 rate increase reflected approximately $100.9 million (subsequently updated to $98.7 million) for recovery of costs associated with the CACJA project. The case also requested the initiation of a CACJA rider for 2016 and 2017, which is anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017. The rate filing was based on a 2015 forecast test year, a requested ROE of 10.35 percent, an electric rate base of $6.39 billion and an equity ratio of 56 percent. As part of the filing, PSCo would transfer approximately $19.9 million from the transmission rider to base rates, which would not impact customer bills. The rider would recover incremental investment and expenses associated with the CACJA project to retire certain coal plants, add pollution control equipment to other existing coal units and add natural gas generation.

In November 2014, several parties filed answer testimony, including the CPUC Staff (Staff) and the OCC. The Staff's position was based on an ROE of 9.11 percent and a 51.24 percent equity ratio. In addition, the Staff proposed that costs associated with the CACJA project be recovered through a rider mechanism. The OCC recommended an ROE of 9.10 percent, a 52.70 percent equity ratio and that a portion of the costs associated with the CACJA project be recovered in base rates and the remainder through a rider mechanism.

In December 2014, PSCo filed rebuttal testimony, revising its requested rate increase to $107.2 million, or 3.79 percent, reflecting an ROE of 10.25 percent and updated information for both the sales and property tax forecasts. PSCo also proposed to recover all costs associated with the CACJA project through the rider beginning in 2015.

On Jan. 23, 2015, PSCo and intervenors filed a comprehensive settlement agreement, subject to CPUC approval, which would result in an overall 2015 revenue increase of approximately $53.3 million, or 1.87 percent. Key terms of the agreement include the following:

- The settlement is based on a 2013 HTY, an ROE of 9.83 percent and an equity ratio of 56 percent;
- It includes the implementation of a forward-looking CACJA rider, effective Jan. 1, 2015, a forward-looking TCA rider, effective Feb. 13, 2015 and tracking mechanisms for pension expense and property taxes; and
- The agreement also includes an earnings test for 2015 through 2017, under which PSCo and customers would share in any earnings on a 50/50 basis if the ROE recognized falls between 9.84 percent and 10.48 percent. The earnings test principles are based primarily on those established in the previous rate case.

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The Staff and OCC's recommendations, PSCo's rebuttal testimony and the terms of the settlement agreement are summarized as follows:

2015 Rate Request (Millions of Dollars)	Staff	OCC	PSCo Rebuttal	Settlement Agreement
PSCo's filed rate request	$136.0	$136.0	$136.0	$136.0
Transfer from TCA rider to base rates	19.9	19.9	19.9	19.9
PSCo's filed revenue requirement deficiency	155.9	155.9	155.9	155.9
Lower ROE	(69.1)	(66.5)	(6.2)	(27.9)
Capital structure	(20.9)	(23.7)	—	—
Rate base adjustments (largely the removal of prepaid pension asset)	(20.8)	2.3	—	—
Adjustment to an HTY	(82.5)	(82.5)	—	(23.9)
Adjustment to use 13-month average rate base	(26.1)	(22.0)	—	—
Rate base adjustments for known and measurable plant through September 2014	21.9	—	—	—
O&M expense adjustments	(7.2)	(16.6)	—	—
Depreciation	—	(3.8)	—	—
Property taxes	—	(12.1)	(5.3)	(5.3)
Remove CACJA from base rates	(62.4)	—	(98.7)	(98.7)
Updated sales forecast	—	—	(15.2)	(15.2)
Prepaid pension amortization	—	—	—	9.5
Non-specified settlement adjustments	—	—	—	(31.7)
Other, net	0.1	0.1	(2.1)	(2.1)
Total base rate (decrease) increase	(111.1)	(68.9)	28.4	(39.4)
CACJA rider mechanism	54.2	—	98.7	97.0
TCA rider mechanism — 2015 forecast test year	—	—	—	15.6
Transfer from TCA rider to base rates	(19.9)	(19.9)	(19.9)	(19.9)
Total revenue impact	$(76.8)	$(88.8)	$107.2	$53.3

In addition to the revenue reflected in the table above, PSCo estimates that it will defer approximately $3.1 million of additional expenses in 2015 as a result of the settlement.

In its original rate case request, PSCo proposed to shorten the depreciable lives for certain assets, which would have resulted in a material increase in depreciation expense. As a result of the settlement, PSCo will not implement the depreciation changes, but will instead file a standalone case to address depreciation, amortization and decommissioning in early 2016. The results of the depreciation case will become effective as part of the 2018 electric rate case.

Settlement rates became effective Feb. 13, 2015 on an interim basis, subject to refund, and the CPUC is expected to issue a final decision regarding the settlement in the first quarter of 2015.

PSCo – Manufacturer's Sales Tax Refund — PSCo has deferred 2012-2014 annual property taxes in excess of $76.7 million as part of its multi-year rate plan with the CPUC. To the extent that PSCo was successful in the manufacturer's sales tax refund lawsuit against the Colorado Department of Revenue, PSCo was to credit such refunds first against certain legal fees, and then against the unamortized deferred property tax balance at the end of 2014.

On June 30, 2014, the Colorado Supreme Court ruled against PSCo's claim that it was due refunds for the payment of sales taxes on purchases of certain equipment from December 1998 to December 2001. As a result of the adverse ruling, PSCo was required to reduce its 2014 property tax deferral by $10 million, as this amount will not be recovered in electric rates.

PSCo – Annual Electric Earnings Test — As part of an annual earnings test, PSCo must share with customers a portion of any annual earnings that exceed PSCo's authorized ROE threshold of 10 percent for 2012-2014. In April 2014, PSCo filed its 2013 earnings test with the CPUC proposing a refund obligation of $45.7 million to electric customers. This tariff was approved by the CPUC in July 2014. As of Dec. 31, 2014, PSCo has also recognized management's best estimate of the expected customer refund obligation for the 2014 earnings test of $74.0 million. PSCo will file its 2014 earnings test with the CPUC in April 2015. The final sharing obligation will be based on the CPUC-approved tariff and could vary from the current estimate.

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SmartGridCity (SGC) Cost Recovery — PSCo requested recovery of $45 million of capital costs and $4 million of annual O&M costs incurred to develop and operate SGC as part of its 2010 electric rate case. In 2011, the CPUC allowed recovery of approximately $28 million of the capital cost and all of the O&M costs. PSCo subsequently requested recovery of the remaining capital investment in SGC, which the CPUC denied in April 2013. Based on the ALJ’s previous recommended decision to deny recovery, PSCo recognized a $10.7 million pre-tax charge in 2012, representing the net book value of the disallowed investment, which was included in O&M expense.

Electric, Purchased Gas and Resource Adjustment Clauses

DSM and the DSMCA — The CPUC approved higher savings goals and a lower financial incentive mechanism for PSCo’s electric DSM energy efficiency programs starting in 2015. 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 are 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.

The CPUC approved the 2014 PSCo electric and gas DSM budget of $87.8 million and $12.3 million, respectively. In October 2014, PSCo filed its 2015-2016 DSM plan, which proposes a 2015 DSM electric budget of $81.6 million and a gas budget of $13.1 million and a 2016 DSM electric budget of $78.7 million and gas budget of $13.6 million. A decision by the ALJ is expected in the second quarter of 2015.

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 asset balance approximately $0.6 million and $21.7 million in 2014 and 2013, respectively. The cumulative credit to the RESA regulatory asset balance was $105.1 million and $104.5 million at Dec. 31, 2014 and Dec. 31, 2013, respectively. The credits include the customers’ share of REC trading margins and the unspent share of carbon offset funds.

In September 2014, an ALJ issued a decision approving a settlement between PSCo, the CPUC Staff, and intervenors to extend the current sharing mechanism without modification through 2017.

Recently Concluded Regulatory Proceedings — FERC

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission formula rates from an HTY formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo’s wholesale transmission and ancillary services revenue by approximately $2.0 million annually.

In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to November 2012, subject to refund, and setting the case for settlement judge or hearing procedures. Several wholesale customers then filed a complaint with the FERC seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012.

In September 2014, PSCo and its transmission customers filed a settlement to resolve the ROE issue in the transmission rate filing and complaint. The FERC approved the settlement in October 2014, providing a 9.72 percent ROE effective retroactive to July 1, 2012 for the PSCo transmission formula rate. Refunds were provided to customers in December 2014.

PSCo – Production Formula Rate ROE Complaint — In August 2013, PSCo's wholesale production customers filed a complaint with the FERC, and requested it reduce the stated ROEs ranging from 10.1 percent through 10.4 percent to 9.04 percent in the PSCo production sales formula rates effective Sept. 1, 2013. In September 2014, PSCo and its wholesale customers filed a settlement to resolve the complaint along with the pending transmission formula rate ROE matters. The FERC approved the settlement in October 2014, providing a 9.72 percent ROE effective for the PSCo production formula rate. Refunds were provided to customers in December 2014.

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SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the PUCT seeking an overall increase in annual revenue of approximately $64.75 million, or 6.7 percent. The filing is based on an HTY ended June 2014, adjusted for known and measurable changes, an ROE of 10.25 percent, an electric rate base of approximately $1.56 billion and an equity ratio of 53.97 percent.

As part of its request, SPS is seeking a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $442 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014.

The following table summarizes the net request:

(Millions of Dollars)	Request
Investment for capital expenditures — post-test year adjustments	$29.60
Depreciation expense	13.90
Wholesale load reductions	12.00
Purchased power capacity costs	3.20
Other, net	6.05
Total	$64.75

The next steps in the procedural schedule are expected to be as follows:

- Intervenor Direct Testimony — April 1, 2015;
- Staff Direct Testimony — April 8, 2015;
- Staff and Intervenor Cross-Rebuttal Testimony — April 22, 2015;
- Rebuttal Testimony — April 24, 2015; and
- Evidentiary Hearing — May 11, 2015.

The parties have agreed the rates will be effective June 11, 2015. A PUCT decision is anticipated in the second half of 2015.

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas seeking a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflected a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the TCRF to zero when the final base rates become effective. In April 2014, SPS revised its request to a net increase of $48.1 million.

The rate filing was based on an HTY ending June 2013, a requested ROE of 10.40 percent, an electric rate base of approximately $1.27 billion and an equity ratio of 53.89 percent. The requested rate increase reflected an increase in depreciation expense of approximately $16 million.

In September 2014, SPS, PUCT staff, and intervenors filed a non-unanimous settlement agreement which would increase SPS' rates by $37 million, or 3.5 percent, retroactive to June 1, 2014. Starting Oct. 1, 2014, SPS began collecting the rate increase through interim rates subject to refund. SPS expects to recover the rate increase for June through September 2014 through a separate surcharge, for which it has recognized approximately $15.4 million of revenue in 2014.

The settlement includes an ROE of 9.7 percent solely for the purpose of calculating the AFUDC and determining baselines in future filings for the TCRF. In October 2014, the ALJs approved the stipulation and recommended that SPS file to implement the surcharge following the PUCT's final order.

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Although the parties to the settlement agreement have not prepared a calculation of the $37 million increase and do not agree about which specific costs are included, or not, in the agreed settlement revenue requirement, SPS' reconciliation of its original request to the settlement increase is as follows:

(Millions of Dollars)	Settlement Agreement
Base rate increase request, January 2014	$81.5
Revisions for updated information	(4.6)
Revised request, April 2014	76.9
Remove proposed increase in depreciation	(16.0)
Remove adjustment allocators for certain wholesale load reduction	(12.0)
Revised amortizations (rate case expenses, pension and other post-employment benefits expense and gain on sale to Lubbock)	(9.0)
Non-specified settlement adjustments	(2.9)
Settlement base rate increase	$37.0

In December 2014, the PUCT approved the settlement and authorized SPS to file to implement the surcharge. In January 2015, SPS filed an application to implement a surcharge of approximately $15.6 million, including interest, to be recovered from March through June 2015, subject to a true-up. A hearing was held in February 2015 and a decision is expected in the first quarter of 2015.

Electric, Purchased Gas and Resource Adjustment Clauses

TCRF Rider — In November 2013, SPS filed with the PUCT to implement the TCRF for Texas retail customers. The requested increase in revenues was $13 million. The PUCT issued an order allowing the TCRF to go into effect on an interim basis effective Jan. 1, 2014. In May 2014, the ALJ terminated the interim TCRF due to a settlement in principle being reached with intervenors and the PUCT staff in the pending Texas electric rate case. In July 2014, the PUCT approved the settlement agreement between the parties allowing SPS to recover $4 million annually through the TCRF. In September 2014, SPS filed a proposal with the PUCT to refund approximately $3.7 million during November 2014 for interim rates collected in excess of the final rates approved. Under a settlement among the parties, SPS implemented the refund in November 2014, pending PUCT approval. The PUCT approved the refund on Dec. 18, 2014.

Pending Regulatory Proceedings — NMPRC

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the NMPRC for an increase in annual revenue of approximately $45.9 million effective in 2014. The rate filing was based on a 2014 FTY, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent.

In September 2013, SPS filed rebuttal testimony, revising its requested rate increase to $32.5 million, based on updated information and an ROE of 10.25 percent. The request reflected a base and fuel increase of $20.9 million, an increase of rider revenue of $12.1 million and a decrease to other of $0.5 million.

In March 2014, the NMPRC approved an overall increase of approximately $33.1 million. The increase reflects a base rate increase of $12.7 million and rider recovery of $18.1 million for renewable energy costs, both based on an ROE of 9.96 percent and an equity ratio of 53.89 percent. Final rates were effective April 5, 2014. In April 2014, the NMAG filed a request for rehearing. The rehearing request was denied by the NMPRC. In June 2014, the NMAG filed an appeal of the NMPRC's denial to the New Mexico Supreme Court. A decision is expected by the second quarter of 2016.

Pending and Recently Concluded Regulatory Proceedings — FERC

SPS – Wholesale Rate Complaints — In April 2012, Golden Spread, a wholesale cooperative customer, filed a rate complaint alleging that the base ROE included in the SPS production formula rate of 10.25 percent, and the SPS transmission base formula rate ROE of 10.77 percent, are unjust and unreasonable. In July 2013, Golden Spread filed a second complaint, again asking that the base ROE in the SPS production and transmission formula rates be reduced to 9.15 and 9.65 percent, respectively.

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In June 2014, the FERC issued orders consolidating the Golden Spread ROE complaints and setting them for settlement judge procedures and hearings and indicated the parties should apply the new two-step discounted cash flow ROE methodology to the proceedings. The FERC established effective dates for the refunds as April 20, 2012 and July 19, 2013. Settlement judge procedures were unsuccessful and the complaints were set for hearing procedures, with an initial ALJ decision to be issued by Nov. 25, 2015 and a final FERC order to be issued no earlier than 2016. In January 2015, Golden Spread filed testimony requesting that wholesale production and transmission formula rates be reduced to 8.78 percent and 9.28 percent, respectively, for the period April 20, 2012 to July 18, 2013, and reduced to 8.51 percent and 9.01 percent, respectively, for the period July 19, 2013 to Oct. 19, 2014.

Golden Spread, along with certain New Mexico cooperatives and the West Texas Municipal Power Agency, separately filed a third rate complaint in October 2014, requesting that the base ROE in the SPS production and transmission formula rates be reduced to 8.61 percent and 9.11 percent, respectively. The complainants requested a refund effective date of Oct. 20, 2014. In January 2015, the FERC issued an order setting the third complaint for hearing procedures and granting the complainants' requested refund effective date.

SPS – FERC Complaint Case Orders — In August 2013, the FERC issued an order on rehearing related to a 2004 complaint case brought by Golden Spread and PNM and an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaint included two key components: 1) PNM's claim regarding inappropriate allocation of fuel costs and 2) a base rate complaint, including the appropriate demand-related cost allocator. The FERC previously determined that the allocation of fuel costs and the demand-related cost allocator utilized by SPS was appropriate.

In the August 2013 Orders, the FERC clarified its previous ruling on the allocation of fuel costs and reaffirmed that the refunds in question should only apply to firm requirements customers and not PNM's contractual load. The FERC also reversed its prior demand-related cost allocator decision. The FERC stated that it had erred in its initial analysis and concluded that the SPS system was a 3CP rather than a 12CP system.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling. In October 2013, the FERC issued orders further considering the requests for rehearing, which are currently pending. As of Dec. 31, 2013, SPS had accrued $44.5 million related to the August 2013 Orders and an additional $5.9 million of principal and interest was accrued during 2014.

On Jan. 30, 2015, SPS filed to revise the production formula rates for six of its wholesale customers, including Golden Spread, effective Feb. 1, 2015. The filing proposes several modifications, including a reduction in wholesale depreciation rates and the use of a 12CP demand-related cost allocator. If approved, principal and interest accruals from the August 2013 Orders would cease as of the effective date. FERC action is pending.

Sale of Texas Transmission Assets — In March 2013, SPS reached an agreement to sell certain segments of SPS' transmission lines and two related substations to Sharyland. In 2013, SPS received all necessary regulatory approvals for the transaction. In December 2013, SPS received $37.1 million and recognized a pre-tax gain of $13.6 million and regulatory liabilities for jurisdictional gain sharing of $7.2 million. The gain is reflected in the consolidated statement of income as a reduction to O&M expenses. In December 2014, Golden Spread submitted a preliminary challenge asserting that the gain should be shared with wholesale transmission customers. SPS has disputed this claim. It is uncertain if the matter will result in a formal proceeding with the FERC.

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 system renewal projects.

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NSP-Minnesota Wind Projects — In October 2013, the MPUC approved two projects totaling 350 MW that will be owned by NSP-Minnesota. In 2014, the NDPSC approved the prudence of the Border Winds Project. The Pleasant Valley wind farm in Minnesota and the Border Winds wind farm projects in North Dakota are anticipated to be operational in late 2015.

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 is the TUCO to Yoakum County to Hobbs Plant, a 345 KV transmission line. This line will connect the TUCO substation near Lubbock, Texas with the Yoakum County substation, continuing on to the Hobbs Plant substation near Hobbs, N.M. SPS anticipates filing CCNs for this line in Texas and in New Mexico in mid-2015. The line is scheduled to be in service in 2020.

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 2015 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, 2014 are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2015	$900.7	$90.3	$374.2	$280.0
2016	659.8	121.8	158.8	221.4
2017	359.6	121.0	161.9	171.7
2018	73.3	65.6	212.3	122.7
2019	44.0	128.5	221.7	114.5
Thereafter	387.3	641.4	732.7	1,152.5
Total	$2,424.7	$1,168.6	$1,861.6	$2,062.8

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 2033 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 $229.8 million, $217.0 million and $261.9 million in 2014, 2013 and 2012, respectively. At Dec. 31, 2014, 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)]

2015	$245.3	$132.9
2016	206.5	104.1
2017	178.0	91.3
2018	140.1	93.2
2019	92.1	98.7
Thereafter	433.7	767.9
Total	$1,295.7	$1,288.1

(a) Excludes contingent energy payments for renewable energy PPAs.

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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 leases the facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under a service arrangement.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had $138.9 million and $144.2 million of capital lease obligations recorded for the arrangement as of Dec. 31, 2014 and 2013, 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 $7.2 million, $6.3 million and $5.7 million for 2014, 2013 and 2012, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	2014	2013
Gas storage facilities	$200.5	$200.5
Gas pipeline	20.7	20.7
Property held under capital leases	221.2	221.2
Accumulated depreciation	(49.0)	(41.8)
Total property held under capital leases, net	$172.2	$179.4

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately $271.9 million, $242.1 million and $217.8 million for 2014, 2013 and 2012, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of $228.2 million, $197.7 million and $174.4 million in 2014, 2013 and 2012, 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
2015	$26.2	$228.3	$254.5	$17.8
2016	23.6	215.4	239.0	17.1
2017	18.4	210.0	228.4	15.0
2018	17.3	211.3	228.6	14.7
2019	21.8	213.3	235.1	14.5
Thereafter	132.9	1,785.1	1,918.0	273.1
Total minimum obligation				352.2

Interest component of obligation	(249.5	)
Present value of minimum obligation	$102.7	[c]

[a] Amounts do not include PPAs accounted for as executory contracts.

[b] PPA operating leases contractually expire through 2033.

[c] Future commitments exclude certain amounts related to Xcel Energy’s 50 percent ownership interest in WYCO.

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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 associated 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 in the future, 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. The Xcel Energy utility subsidiaries had approximately 3,698 MW and 3,338 MW of capacity under long-term PPAs as of Dec. 31, 2014, and 2013, respectively, with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 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 2016 and 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 in the future, 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, and 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, and 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 in the future, 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.

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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, 2014	Dec. 31, 2013
Current assets	$6,609	$7,982
Property, plant and equipment, net	53,047	65,451
Other noncurrent assets	1,503	1,654
Total assets	$61,159	$75,087
Current liabilities	$7,774	$11,388
Mortgages and other long-term debt payable	31,207	38,049
Other noncurrent liabilities	619	707
Total liabilities	$39,600	$50,144

Technology Agreements — Xcel Energy has a contract that extends through June 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 $111.3 million, $90.3 million and $86.5 million associated with the IBM contract in 2014, 2013 and 2012, respectively.

Xcel Energy’s contract with Accenture for information technology services extends through January 2017. The contract is cancelable at Xcel Energy’s option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $27.3 million, $23.7 million and $18.3 million associated with the Accenture contract in 2014, 2013 and 2012, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2015	$33.0	$9.0
2016	31.9	8.9
2017	32.0	—
2018	31.5	—
2019	15.7	—
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, 2014 and 2013, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

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Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding as of Dec. 31, 2014:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of customer loans for the Farm Rewiring Program [(a)]	NSP-Wisconsin	$1.0	$0.2	(e)
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases [(b)]	Xcel Energy Inc.	8.1	—	(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		$13.9	$0.2	
Guarantee performance and payment of surety bonds for Xcel Energy Inc. and its subsidiaries [(d)]	Xcel Energy Inc.	$31.4	(i)	(h)

(a) The term of this guarantee expires in 2018, which is the final scheduled repayment date for the loans. As of Dec. 31, 2014, 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 Xcel Energy Inc. or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy 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 hazardous materials and wastes to that site.

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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 Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted wood treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The EPA issued its Record of Decision (ROD) in 2010, which describes the preferred remedy the EPA has selected for the cleanup of the Ashland site. For the Sediments at the Ashland Site, the ROD preferred remedy is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). The ROD also identifies the possibility of a wet conventional dredging only remedy for the Sediments (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study.

In 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future remediation at the Ashland site. As a result of settlement negotiations with NSP-Wisconsin, the EPA agreed to segment the Ashland site into separate areas. The first area (Phase I Project Area) includes soil and groundwater in Kreher Park and the Upper Bluff. The second area includes the Sediments.

In October 2012, a settlement among the EPA, the WDNR, the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin was approved by the U.S. District Court for the Western District of Wisconsin. This settlement resolves claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the settlement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. Demolition activities occurred at the Ashland site in 2013. The final design for the soil, including excavation and treatment, as well as containment wall remedies was submitted to the EPA in April 2014 and work commenced in May 2014. A preliminary design for the groundwater remedy was also submitted to the EPA in April 2014 and those activities are expected to commence in 2015. Based on these updated designs, the cost estimate for the cleanup of the Phase I Project Area is approximately $54 million, of which approximately $28 million has already been spent. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and what remedy will be implemented at the site to address the Sediments. It is NSP-Wisconsin's view that the Hybrid Remedy is not safe or feasible to implement. The EPA's ROD for the Ashland site 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. In November 2013, NSP-Wisconsin submitted a revised Wet Dredge pilot study work plan proposal to the EPA. In May 2014, NSP-Wisconsin entered into a final administrative order on consent for the Wet Dredge pilot study with the EPA. In September 2014, the EPA granted an extension of time to perform the pilot in the summer of 2015.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. Trial for this matter is scheduled for April-May of 2015. Negotiations between the EPA, NSP-Wisconsin and several of the other PRPs regarding the PRPs' fair share of the cleanup costs for the Ashland site are also ongoing. A settlement in principle has been reached with two PRPs, Wisconsin Central Ltd. and Soo Line Railroad Co. (collectively, the "Railroad PRPs"), the EPA and NSP-Wisconsin resolving claims relating to the Railroad PRPs' share of the costs of cleanup at the Ashland site. Under the agreement, the Railroad PRPs have agreed to contribute $10.5

million to the costs of the cleanup at the Ashland site. The agreement is currently subject to a 30-day public comment period and must be entered by the U.S. District Court for the Western District of Wisconsin before it will become final. It is anticipated that the agreement will be entered in the first quarter of 2015. As discussed below, existing PSCW policy requires that any payments received from PRPs be used to reduce the amount of the cleanup costs ultimately recovered from customers.

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At Dec. 31, 2014 and 2013, NSP-Wisconsin had recorded a liability of $107.6 million and $104.6 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $28.9 million and $25.2 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 Ashland site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. Under the established PSCW policy, external MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin retail rate case process. Any payments received from insurance carriers or PRPs are recorded as a reduction of the regulatory asset. Once deferred MGP remediation costs are determined by the PSCW to be prudent, utilities are allowed to recover those deferred costs in natural gas rates, typically over a four- to six-year amortization period. The PSCW historically has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation.

In the 2013 rate case decision, the PSCW recognized the potential magnitude of the future liability for the cleanup at the Ashland site and granted an exception to its existing policy at the request of NSP-Wisconsin. The elements of this exception include: (1) approval to begin recovery of estimated Phase 1 Project costs beginning on Jan. 1, 2013; (2) approval to amortize these estimated costs over a ten-year period; and (3) approval to apply a three percent carrying cost to the unamortized regulatory asset. In the 2014 rate case decision, the PSCW continued the cost recovery treatment with respect to the 2013 and 2014 cleanup costs for the Phase I Project Area. The PSCW determined the timing of the cleanup of the Sediments was uncertain and declined NSP-Wisconsin's request to begin cost recovery for this portion of the cleanup in 2014 rates. However, the PSCW allowed NSP-Wisconsin to increase its 2014 amortization expense related to the cleanup by an additional $1.1 million to offset the need for a rate decrease for the natural gas utility.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where hazardous or other regulated materials may have been deposited. Xcel Energy has identified eight 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 2015. Xcel Energy had accrued $2.1 million and $5.1 million for all of these sites at Dec. 31, 2014 and 2013, 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 June 2013, the EPA published a proposed 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. The final rule is now expected in September 2015. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017, but no later than July 2022. The impact of this rule on Xcel Energy is uncertain at this time.

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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 is approximately $46 million with the majority needed for NSP-Minnesota. Xcel Energy believes at least three NSP-Minnesota 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 $145 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 April 2014, the EPA and the U.S. Army Corps of Engineers issued a proposed rule that significantly expands the types of water bodies regulated under the CWA. If finalized as proposed, this rule could delay the siting of new pipelines, transmission lines and distribution lines, increase project costs and expand permitting and reporting requirements. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and cannot be determined at this time. A final rule is not anticipated before the second quarter of 2015.

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2010, the EPA published a proposed rule on the regulation of coal combustion byproducts (coal ash) as hazardous or nonhazardous waste. The EPA issued a pre-publication version of the final rule in December 2014, which once promulgated will impose new rules to regulate coal ash as a nonhazardous solid waste. Xcel Energy's costs for the management and disposal of coal ash will not significantly increase under the new rule.

Air

GHG Emission Standard for Existing Sources — In June 2014, the EPA published its proposed rule on GHG emission standards for existing power plants. Comments were due to the EPA on Dec. 1, 2014 and a final rule is anticipated in mid-summer 2015. Following adoption of the final rule, states must develop implementation plans by June 2016, with the possibility of an extension to June 2017 (June 2018 if submitting a joint plan with other states). Among other things, the proposed rule would require that state plans include enforceable measures to ensure emissions from existing power plants in the state achieve the EPA's state-specific interim (2020-2029) and final (2030 and thereafter) emission performance targets. The plan will likely require additional emission reductions in states in which Xcel Energy operates. It is not possible to evaluate the impact of existing source standards until the EPA promulgates a final rule and states have adopted their applicable state plans.

GHG NSPS Proposal — In January 2014, the EPA re-proposed a GHG NSPS for newly constructed power plants which would set performance standards (maximum carbon dioxide emission rates) for coal- and natural gas-fired power plants. For coal power plants, the NSPS requires an emissions level equivalent to partial carbon capture and storage (CCS) technology; for gas-fired power plants, the NSPS reflects emissions levels from combined cycle technology with no CCS. The EPA continues to propose that the NSPS not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. A final rule is anticipated in mid-summer 2015. It is not possible to evaluate the impact of the re-proposed NSPS until its final requirements are known.

GHG NSPS for Modified and Reconstructed Power Plants — In June 2014, the EPA published a proposed NSPS that would apply to GHG emissions from power plants that are modified or reconstructed. A final rule is anticipated in mid-summer 2015. A modification is a change to an existing source that increases the maximum achievable hourly rate of emissions. A reconstruction involves the replacement of components at a unit to the extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit. The proposed standards would not require installation of CCS technology. Instead, the proposed standard for coal-fired power plants would require a combination of best operating practices and equipment upgrades. The proposal for gas-fired power plants would require emissions standards based on efficient combined cycle technology. It is not possible to evaluate the impact of these proposed standards until the final requirements are known. In addition, it is not clear whether these requirements, once adopted, would apply to future changes at Xcel Energy's power plants.

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.

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In August 2012, the D.C. Circuit vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated the EPA must continue administering CSAPR's predecessor rule pending adoption of a valid replacement. In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Supreme Court held that the EPA's rule design did not violate the CAA and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand. In October 2014, the D.C. Circuit granted the EPA's request to begin to implement CSAPR by imposing its 2012 compliance obligations starting in January 2015. In addition, the D.C. Circuit set a briefing schedule and plans to hear arguments on the remaining issues in the case in February 2015. While the litigation continues, the EPA will begin to administer the CSAPR in 2015.

Multiple changes to the SPS system since 2011 will substantially reduce estimated costs of complying with the CSAPR. These include the addition of 700 MW of wind power, the construction of Jones Units 3 and 4 to meet reserve requirements and provide quick start capability, reduced wholesale load and new PPAs, installation of NOx combustion controls on Tolk Units 1 and 2 and completion of certain transmission projects. As a result, SPS estimates compliance with the CSAPR in 2015 will cost approximately $7 million.

NSP-Minnesota can operate within its CSAPR emission allowance allocations, particularly given the cessation of coal operations at Black Dog Units 3 and 4 before mid-April 2015. NSP-Wisconsin can operate within its CSAPR emission allowance allocation for SO_2 due to cessation of coal combustion at Bay Front Unit 5. NSP-Wisconsin anticipates compliance with the CSAPR for NOx in 2015 through operational changes or allowance purchases. CSAPR compliance in 2015 is not expected to have a material impact on the results of operations, financial position or cash flows.

EGU Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective in April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. Xcel Energy expects to comply with the EGU MATS rule through a combination of mercury and other emission control projects. In 2014, the U.S. Supreme Court decided to review the D.C. Circuit's decision that upheld the MATS standard. It is not yet known what impact the Supreme Court's decision may have on the MATS standard or its implementation schedule. Xcel Energy believes EGU MATS costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

Minnesota Mercury Legislation — NSP-Minnesota installed sorbent control systems at the Sherco Unit 3 and A.S. King generating plants and completed installation of mercury controls on Sherco Units 1 and 2. Installation costs through Dec. 31, 2014 were $12.9 million for the mercury controls on the units and NSP-Minnesota believes these costs will be recoverable through regulatory mechanisms.

Industrial Boiler (IB) MACT Rules — In 2011, the EPA finalized IB MACT rules to regulate boilers and process heaters fueled with coal, biomass and liquid fuels, which would apply to NSP-Wisconsin's Bay Front Units 1 and 2. The controls to meet the requirements were substantially complete as of Dec. 31, 2014, with final work targeted to be finished in May 2015. The final capital cost is estimated to be approximately $21 million.

Regional Haze Rules — The regional haze program is designed to address widespread, regionally homogeneous 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 SIP, 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 the facilities included in 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. Installation of emission controls at Pawnee was completed in 2014 at a cost of $272.6 million. Installation of the emission controls at Hayden Unit 1 is scheduled for 2015 and Hayden Unit 2 is scheduled for 2016 at an estimated combined cost of $84.6 million. PSCo anticipates these costs will be fully recoverable in rates.

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In March 2013, WildEarth Guardians petitioned the U.S. Court of Appeals for the 10th Circuit to review the EPA's decision approving the Colorado SIP. WildEarth Guardians has stated it will challenge the BART determination made for Comanche Units 1 and 2. In comments before the EPA, WildEarth Guardians urged that current emission limitations be made more stringent or that SCR be added to the units. In September 2014, the EPA filed a request with the Court to remand the case to the EPA for additional explanation of the EPA's decision approving the BART determination for Comanche Units 1 and 2. In October 2014, the Court granted the EPA's request and vacated the current briefing schedule. The EPA has provided required status reports.

In 2010, two environmental groups petitioned the DOI to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege the Colorado BART rule is inadequate to satisfy the CAA mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota
In 2009, the 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 concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The combustion controls were installed first and the scrubber upgrades were completed in December 2014. These emission controls cost $46.6 million. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

After the CSAPR was adopted in 2011, the MPCA supplemented its Minnesota SIP, 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 as strengthening the Minnesota SIP, but avoided characterizing them as BART limits.

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). NSP-Minnesota and other regulated parties were denied intervention. 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 October 2014, the Eighth Circuit set a briefing schedule that will be completed in early 2015. An argument date has not been set. If this litigation ultimately results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

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. The EPA currently plans to issue its final rule in August 2015.

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 its December 2014 proposal, the EPA plans to disapprove the reasonable progress portions of the Texas SIP and instead adopt a Federal Implementation Plan. For SPS, the EPA proposed to require dry scrubbers on both Tolk units to reduce SO_2 emissions to help achieve reasonable progress goals the EPA would establish for Texas and

Oklahoma national parks and wilderness areas. As proposed, the dry scrubbers would need to be installed and operating within five years of the EPA's final action, currently expected in August 2015. SPS plans to file comments objecting to the installation of dry scrubbers on the units. Whether dry scrubbers are required is dependent on the EPA's final decision. If required, they would cost approximately $600 million, with an annual operating cost of approximately $10.4 million.

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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. The EPA is required to make its own determination whether there is RAVI-type impairment in these parks and examine which sources may cause or contribute to any RAVI impact that is identified. After studying the national parks and evaluating multiple sources, if the EPA finds that Sherco Units 1 and 2 cause or contribute to RAVI in the national parks, the EPA would then evaluate whether the level of controls required by the MPCA is appropriate. The EPA has stated it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota 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. The lawsuit alleges the EPA has failed to perform a nondiscretionary duty to determine BART for Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. The District Court denied NSP-Minnesota's motion to intervene in July 2013. NSP-Minnesota appealed this decision to the Eighth Circuit, which on July 23, 2014, reversed the District Court and found that NSP-Minnesota has standing and a right to intervene.

In June 2014, the EPA and the plaintiffs lodged a consent decree with the District Court. The public comment period on the draft consent decree has been completed. The EPA is evaluating comments and will determine whether to enter the consent decree with the District Court. The draft consent decree would establish a schedule whereby the EPA would issue a proposal on Feb. 27, 2015, or 30 days after the District Court enters the consent decree if the decree is entered after Feb. 27, 2015. The proposal would provide the EPA's analysis of whether visibility impairment in the national parks is reasonably attributable to Sherco Units 1 and 2. If the EPA determines that it is, the draft consent decree requires the EPA to make a final RAVI BART determination for these units by Aug. 31, 2015. If the EPA determines that it is not, the EPA would not determine BART for Sherco Units 1 and 2. NSP-Minnesota filed comments opposing the proposed consent decree and will object to its entry given NSP-Minnesota's right to intervene in the litigation and thus participate in the negotiation of any purported settlement of the case.

Revisions to the National Ambient Air Quality Standards (NAAQS) for PM — In December 2012, the EPA lowered the primary health-based NAAQS for annual average fine PM and retained the current daily standard for fine PM. In areas where Xcel Energy operates power plants, current monitored air concentrations are below the level of the final annual primary standard. In December 2014, the EPA issued its final designations, which did not include areas in any states in which Xcel Energy operates.

Revisions to the NAAQS for Ozone — In December 2014, the EPA proposed to revise the NAAQS for ozone by lowering the eight-hour standard from 0.075 parts per million (ppm) to a level within the range of 0.065-0.070 ppm. The EPA is also taking comment on a level for the standard as low as 0.060 ppm. In areas where Xcel Energy operates, current monitored air quality concentrations are above the proposed level of 0.070 ppm in the Texas panhandle and in the Denver Metropolitan Area. In addition, current monitored air quality concentrations are above the proposed level of 0.065 ppm in the Twin Cities Metropolitan Area in Minnesota. Current monitored air quality concentrations in areas of Wisconsin where Xcel Energy operates are below the range of the proposed standard. The EPA is expected to adopt a new ozone standard in a final rule to be issued in October 2015. Depending on the level of the standard, impacted states would study the sources of the nonattainment and make emission reduction plans to attain the standards. These plans would be due to the EPA in 2020 or 2021. Such plans could include installation of further NOx controls on power plants. It is not possible to evaluate the impact of this proposal until the final standard is adopted, the designation of nonattainment areas is made in late 2017 based on air quality data years 2014-2016, and any required state plans are developed.

PSCo NOV — In 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Generating Station in Colorado. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid to late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo 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. PSCo 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.

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NSP-Minnesota NOV — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the 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 the electric production includes certain plants at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. This asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota, NSP-Wisconsin, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination dates on the ARO recognition for ash-containment facilities at steam plants were the in-service dates of the various facilities. 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, with the origination dates being the in-service date of the various facilities.

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, treated poles, 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. These assets have numerous in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

In December 2014, the EPA issued a pre-publication version of a final rule imposing requirements for activities involving coal ash waste. The ruling, once effective, will not result in the creation of a new legal obligation and Xcel Energy’s estimated cash flows for the closure of coal ash landfills and impoundments are not expected to significantly increase as a result of the ruling.

For the nuclear assets, the ARO associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI, originated with the in-service date of the facility. See Note 14 for further discussion of nuclear obligations.

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A reconciliation of Xcel Energy's AROs for the years ended Dec. 31, 2014 and 2013 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Accretion	Cash Flow Revisions	Ending Balance Dec. 31, 2014 [(a)]
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) 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.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2013	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Ending Balance Dec. 31, 2013
Electric plant						
Nuclear production decommissioning	$1,546,358	$—	$—	$81,940	$—	$1,628,298
Steam and other production ash containment	61,735	—	—	2,105	15,513	79,353
Steam and other production asbestos	45,461	—	(1,059)	2,551	3,874	50,827
Wind production	35,864	—	—	1,600	—	37,464
Electric distribution	24,150	—	—	708	(12,672)	12,186
Other	3,152	—	—	240	159	3,551
Natural gas plant						
Gas transmission and distribution	1,258	—	—	81	(141)	1,198
Other	—	575	—	—	—	575
Common and other property						
Common general plant asbestos	1,197	—	—	66	(783)	480
Common miscellaneous	621	—	—	59	778	1,458
Total liability	$1,719,796	$575	$(1,059)	$89,350	$6,728	$1,815,390

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.6 billion as of Dec. 31, 2013, 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; therefore, an ARO has not been recorded for these facilities.

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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)	2014	2013
NSP-Minnesota	$396	$378
NSP-Wisconsin	123	116
PSCo	366	359
SPS	68	53
Total Xcel Energy	$953	$906

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $13.6 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 $13.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $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 $17.9 million for business interruption insurance and $43.6 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.

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Employment, Tort and Commercial Litigation

Exelon Wind (formerly John Deere Wind) Complaint — Several lawsuits in Texas state and federal courts and regulatory proceedings have arisen out of a dispute concerning SPS' payments for energy and capacity produced from the Exelon Wind subsidiaries' projects. There are two main areas of dispute. First, Exelon Wind claims that it established legally enforceable obligations (LEOs) for each of its 12 wind facilities in 2005 through 2008 that require SPS to buy power based on SPS' forecasted avoided cost as determined in 2005 through 2008. Although SPS has refused to accept Exelon Wind's LEOs, SPS accepts that it must take energy from Exelon Wind under SPS' PUCT-approved Qualifying Facilities (QF) Tariff. Second, Exelon Wind has raised various challenges to SPS' PUCT-approved QF Tariff, which became effective in August 2010. On Jan.16, 2015, Exelon Wind filed motions to dismiss or notices of non-suits for its state and federal lawsuits regarding the QF tariff, and for its state and federal lawsuits and regulatory proceedings regarding the LEOs. Later in January, the PUCT and state and federal courts issued orders dismissing the cases. The only remaining proceedings are pending before the FERC (one regarding the QF Tariff and the other regarding the LEOs).

SPS believes the likelihood of loss in these proceedings is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there were unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for December 2000 through June 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the Ninth Circuit.

In an order issued in August 2007, the Ninth Circuit remanded the proceeding back to the FERC and indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Ninth Circuit denied a petition for rehearing in April 2009, and the mandate was issued.

The FERC issued an order on remand establishing principles for the review proceeding in October 2011. In September 2012, the City of Seattle filed its direct case against PSCo and other Pacific Northwest sellers claiming refunds for the period January 2000 through June 2001. The City of Seattle indicated that for the period June 2000 through June 2001 PSCo had sales to the City of Seattle of approximately $50 million. The City of Seattle did not identify specific instances of unlawful market activity by PSCo, but rather based its claim for refunds on market dysfunction in the Western markets. PSCo submitted its answering case in December 2012.

In April 2013, the FERC issued an order on rehearing. The FERC confirmed that the City of Seattle would be able to attempt to obtain refunds back from January 2000, but reaffirmed the transaction-specific standard that the City of Seattle and other complainants would have to comply with to obtain refunds. In addition, the FERC rejected the imposition of any market-wide remedies. Although the FERC order on rehearing established the period for which the City of Seattle could seek refunds as January 2000 through June 2001, it is unclear what claim the City of Seattle has against PSCo prior to June 2000. In the proceeding, the City of Seattle does not allege specific misconduct or tariff violations by PSCo but instead asserts generally that the rates charged by PSCo and other sellers were excessive.

A hearing in this case was held before a FERC ALJ and concluded in October 2013. In March 2014, the FERC ALJ issued an initial decision which rejected all of the City of Seattle's claims against PSCo and other respondents. With respect to the period Jan. 1, 2000 through Dec. 24, 2000, the FERC ALJ rejected the City of Seattle's assertion that any of the sales made to the City of Seattle resulted in an excessive burden to the City of Seattle, the applicable legal standard for the City of Seattle's challenges during this period. With respect to the period Dec. 25, 2000 through June 20, 2001, the FERC ALJ concluded that the City of Seattle had failed to establish a causal link between any contracts and any claimed unlawful market activity, the standard required by the FERC in its remand order. The City of Seattle contested the FERC ALJ's initial decision by filing a brief on exceptions to the FERC. PSCo filed a brief answering the City of Seattle's exception. This matter is now pending a decision by the FERC.

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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 FERC's standard has been challenged on appeal to 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.

Biomass Fuel Handling Reimbursement — NSP-Minnesota has a PPA through which it procures energy from Fibrominn, LLC (Fibrominn). Under this agreement, NSP-Minnesota is charged for certain costs of transporting biomass fuels that are delivered to Fibrominn's generation facility. Fibrominn has demanded additional cost reimbursement for certain transportation costs incurred since 2007, as well as reimbursement for similar costs in future periods. Fibrominn claims that it is entitled to reimbursement from NSP-Minnesota for past transportation costs of approximately $20 million. NSP-Minnesota has evaluated Fibrominn's claim and based on the terms of the PPA with Fibrominn and its current understanding of the facts, NSP-Minnesota disputes the validity of Fibrominn's claim, on the ground that, among other things, it seeks to impose contractual obligations on NSP-Minnesota that are neither supported by the terms nor the intent of the PPA. NSP-Minnesota has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, NSP-Minnesota is currently unable to determine the amount of reasonably possible loss. If a loss were sustained, NSP-Minnesota would attempt to recover these fuel-related costs in rates. No accrual has been recorded for this matter.

Nuclear Power Operations and Waste Disposal

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 contract between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the Court awarded NSP-Minnesota $116.5 million in damages. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 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, estimated to be an additional $100 million. In January 2014, the United States proposed, and NSP-Minnesota accepted, an extension to the settlement agreement which will allow NSP-Minnesota to recover spent fuel storage costs through 2016. The extension does not address costs for used fuel storage after 2016; such costs could be the subject of future litigation. In December 2014, NSP-Minnesota received a settlement payment of $32.8 million. NSP-Minnesota has received a total of $214.7 million of settlement proceeds as of Dec. 31, 2014. Amounts received from the installments, except for approved reductions such as legal costs, will be subsequently returned to customers through a reduction of future rate increases or credited through another regulatory mechanism.

Other Contingencies

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. The fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Effective May 2014, the DOE set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately $5 million in 2014, $10 million in 2013 and $12 million in 2012. In total, NSP-Minnesota paid approximately $452.1 million to the DOE through Dec. 31, 2014. See Note 13 — Nuclear Waste Disposal Litigation for further discussion.

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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 38 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 periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota's 2011 nuclear decommissioning study in November 2012. This cost study quantified decommissioning costs in 2011 dollars and utilized escalation rates of 3.63 percent per year for plant removal activities, and 2.63 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

In December 2014, NSP-Minnesota submitted its most recent nuclear decommissioning filing to the MPUC, which included an update to the decommissioning cost study and requested an annual funding requirement of $14.0 million starting in 2016. A decision on the filing is expected in late 2015 or early 2016.

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 $14.2 million to be recovered in utility customer rates. This cost study assumes the external decommissioning fund will earn an after-tax return between 4.57 percent and 5.53 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, 2014, 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)	2014	2013
Estimated decommissioning cost obligation from most recently approved study (2011 dollars)	$2,694,079	$2,694,079
Effect of escalating costs (to 2014 and 2013 dollars, respectively, at 3.63/2.63 percent)	289,907	189,924
Estimated decommissioning cost obligation (in current dollars)	2,983,986	2,884,003
Effect of escalating costs to payment date (3.63/2.63 percent)	5,597,302	5,697,285
Estimated future decommissioning costs (undiscounted)	8,581,288	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 2.82 percent and 4.19 percent for 2014 and 2013, respectively)	(5,044,470)	(6,215,050)
Discounted decommissioning cost obligation	$3,536,818	$2,366,238
Assets held in external decommissioning trust	$1,703,921	$1,627,026
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	1,832,897	739,212

Decommissioning expenses recognized as a result of regulation include the following components:

(Thousands of Dollars)	2014	2013	2012
Annual decommissioning recorded as depreciation expense: [a]			
Externally funded	$7,138	$6,402	$—
Internally funded (including interest costs)	—	—	(1,251)
Net decommissioning expense recorded	$7,138	$6,402	$(1,251)

[a] Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

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The reduction to expense for internally-funded portions in 2012 was a direct result of the 2008 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the previously licensed operating life of the unit (2010 for Monticello, 2013 for PI Unit 1 and 2014 for PI Unit 2). Due to the immaterial amount remaining in the internal fund, the entire remaining amount was unwound for PI 1 and 2 in 2012. As of Dec. 31, 2013, there was no balance remaining in the internally funded decommissioning account. The 2011 nuclear decommissioning filing approved in 2012 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, 2014 and 2013 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2014		Dec. 31, 2013	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations (a)	9	Various	$95,054	$1,402,360	$118,179	$1,192,808
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	395,329	—	359,215
Contract valuation adjustments (b)	1, 11	Term of related contract	17,730	144,273	3,620	153,393
Net AROs (c)	1, 13, 14	Plant lives	—	189,056	—	160,544
Conservation programs (d)	1	One to six years	61,866	58,174	55,088	63,275
Environmental remediation costs	1, 13	Various	4,594	149,812	4,735	119,175
Renewable resources and environmental initiatives	13	One to four years	24,891	29,902	46,076	37,858
Depreciation differences	1	One to seventeen years	10,700	104,743	10,918	95,844
Purchased power contract costs	13	Term of related contract	858	69,908	—	68,182
Losses on reacquired debt	4	Term of related debt	5,258	31,276	5,525	36,534
Nuclear refueling outage costs	1	One to two years	62,499	19,745	86,333	36,477
Gas pipeline inspection and remediation costs	12	Various	9,981	21,869	5,416	33,884
Recoverable purchased natural gas and electric energy costs	1	One to two years	68,841	4,745	42,288	15,495
State commission adjustments	1	Plant lives	571	26,092	444	14,204
PI EPU (e)	12	Pending rate cases	8,743	67,379	—	69,668
Property tax			28,024	31,429	18,427	30,626

	One to three years				
Other	Various	44,448	28,124	20,752	22,036
Total regulatory assets		$444,058	$2,774,216	$417,801	$2,509,218

(a) Includes $282.4 million and $303.3 million for the regulatory recognition of the NSP-Minnesota pension expense of which $23.8 million and $23.2 million is included in the current asset at Dec. 31, 2014 and 2013, respectively. Also included are $26.1 million and $17.7 million of regulatory assets related to the nonqualified pension plan of which $2.5 million and $2.2 million is included in the current asset at Dec. 31, 2014 and 2013, respectively.

(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) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(e) For the canceled PI EPU project, NSP-Minnesota has addressed recovery of incurred costs in the pending multi-year rate case.

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The components of regulatory liabilities shown on the consolidated balance sheets at Dec. 31, 2014 and 2013 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2014		Dec. 31, 2013	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Plant removal costs	1, 13	Plant lives	$—	$953,660	$—	$906,403
Deferred electric and steam production and natural gas costs	1	Less than one year	88,527	—	96,574	—
DOE settlement	12	One to two years	49,492	—	44,208	1,131
Investment tax credit deferrals	1, 6	Various	—	52,666	—	56,535
Deferred income tax adjustment	1, 6	Various	—	48,622	—	43,581
Conservation programs [b]	1, 12	Less than one year	103,351	—	19,531	—
Contract valuation adjustments [a]	1, 11	Term of related contract	55,751	2,521	54,455	6,849
Gain from asset sales	12	One to three years	2,893	4,472	12,859	4,568
Renewable resources and environmental initiatives	12, 13	Various	10,427	10,376	2,499	1,412
Low income discount program		Less than one year	3,355	—	6,229	—
PSCo earnings test	12	One to two years	57,127	42,819	22,891	19,203
Pipeline inspection		Various	13,970	642	—	—
Excess depreciation reserve		Various	10,999	—	—	—
Other		Various	14,837	47,651	15,523	19,713
Total regulatory liabilities			$410,729	$1,163,429	$274,769	$1,059,395

(a) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

At Dec. 31, 2014 and 2013, approximately $323 million and $306 million of Xcel Energy's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes PI EPU costs, 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, 2014 and 2013 were as follows:

	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)

(Thousands of Dollars)	Year Ended Dec. 31, 2013 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 at Jan. 1	$(61,241)	$(99)	$ (51,313)	$(112,653)
OCI before reclassifications	12	176	1,408	1,596
Losses reclassified from net accumulated other comprehensive loss	1,476	—	3,306	4,782
Net current period OCI	1,488	176	4,714	6,378
Accumulated other comprehensive (loss) income at Dec. 31	$(59,753)	$77	$ (46,599)	$(106,275)

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Reclassifications from accumulated other comprehensive loss for the years ended Dec. 31, 2014 and 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Year Ended Dec. 31, 2014		Year Ended Dec. 31, 2013	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$3,836	[a]	$4,107	[a]
Vehicle fuel derivatives	(55	) [b]	(90	) [b]
Total, pre-tax	3,781		4,017	
Tax benefit	(1,493	)	(2,541	)
Total, net of tax	2,288		1,476	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	5,998	[c]	7,077	[c]
Prior service (credit) cost	(344	) [c]	372	[c]
Transition obligation	—	[c]	8	[c]
Total, pre-tax	5,654		7,457	
Tax benefit	(2,159	)	(4,151	)
Total, net of tax	3,495		3,306	
Total amounts reclassified, net of tax	$5,783		$4,782	

(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 commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $83.1 million and $87.1 million as of Dec. 31, 2014 and 2013, 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.

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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
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	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

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2012					
Operating revenues from external customers	$8,517,296	$1,537,374	$73,553	$—	$10,128,223
Intersegment revenues	1,169	1,425	—	(2,594)	—
Total revenues	$8,518,465	$1,538,799	$73,553	$(2,594)	$10,128,223
Depreciation and amortization	$801,649	$115,038	$9,366	$—	$926,053
Interest charges and financing costs	397,457	49,456	119,324	—	566,237
Income tax expense (benefit)	465,626	50,322	(65,745)	—	450,203
Net income (loss)	851,929	98,061	(44,761)	—	905,229

18. Summarized Quarterly Financial Data (Unaudited)

(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

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(Amounts in thousands, except per share data)	Quarter Ended March 31, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013
Operating revenues	$2,782,849	$2,578,913	$2,822,338	$2,730,822
Operating income	454,624	402,236	665,113	325,582
Net income	236,570	196,857	364,752	150,055
EPS total — basic	$0.48	$0.40	$0.73	$0.30
EPS total — diluted	0.48	0.40	0.73	0.30
Cash dividends declared per common share	0.27	0.28	0.28	0.28

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, 2014, 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, 2014 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.

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 2015 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 2015 Annual Meeting of Shareholders, which is incorporated by reference.

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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 2015 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 2015 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 2015 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, 2014.
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, 2014, 2013 and 2012.
Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2014, 2013 and 2012.
Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2014, 2013 and 2012.
Consolidated Balance Sheets — As of Dec. 31, 2014 and 2013.
Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2014, 2013 and 2012.
Consolidated Statements of Capitalization — As of Dec. 31, 2014 and 2013.

2. Schedule I — Condensed Financial Information of Registrant.
Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2014, 2013 and 2012.

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.

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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*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (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 September 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)).

NSP-Minnesota

4.10*	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 December 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).
4.11*	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).
4.12*	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).
4.13*	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).
4.14*	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).
4.15*	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).

4.16*	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).
4.17*	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).
4.18*	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).
4.19*	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).
4.20*	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)).
4.21*	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)).
4.22*	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)).
4.23*	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)).

NSP-Wisconsin

4.24*	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).
4.25*	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).
4.26*	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).
4.27*	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).
4.28*	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 September 30, 2003).
4.29*	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)).
4.30*	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)).
4.31*	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

4.32*	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)).
4.33*	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)

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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

4.34*	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).
4.35*	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).
4.36*	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).
4.37*	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)).
4.38*	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)).
4.39*	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)).
4.40*	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)).
4.41*	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)).
4.42*	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)).
4.43*	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)).

SPS

4.44*	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).
4.45*	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 September 30, 2003).
4.46*	

	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).
4.47*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).
4.48*	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))
4.49*	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)).

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4.50*	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)).
4.51*	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)).
4.52*	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)).
4.53*	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 Chang-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).

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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)).

NSP-Minnesota

10.25*	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)).
10.26*	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).
10.27*	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

10.28*	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).
10.29*	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

10.30*	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)).
10.31*	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)).
10.32*	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).

10.33*	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).
10.34*	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

10.35*	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).
10.36*	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)).
10.37*	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)).

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10.38*	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)).
10.39*	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)).
10.40*	Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and SPS.
10.41*	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, 2014 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.

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SCHEDULE I

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

	Year Ended Dec. 31		
	2014	2013	2012
Income			
Equity earnings of subsidiaries	$1,077,714	$1,018,783	$976,395
Total income	1,077,714	1,018,783	976,395
Expenses and other deductions			
Operating expenses	19,756	18,513	15,948
Other income	(537)	(206)	(652)
Interest charges and financing costs	84,830	102,914	116,731
Total expenses and other deductions	104,049	121,221	132,027
Income before income taxes	973,665	897,562	844,368
Income tax benefit	(47,641)	(50,672)	(60,861)
Net income	$1,021,306	$948,234	$905,229
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $(2,528), $5,897 and $(2,331), respectively	$(4,022)	$4,714	$(3,311)
Derivative instruments, net of tax of $1,390, $2,558 and $(9,906), respectively	2,125	1,488	(15,503)
Other, net of tax of $21, $117 and $135, respectively	33	176	196
Other comprehensive (loss) income	(1,864)	6,378	(18,618)
Comprehensive income	$1,019,442	$954,612	$886,611
Weighted average common shares outstanding:			
Basic	503,847	496,073	487,899
Diluted	504,117	496,532	488,434
Earnings per average common share:			
Basic	$2.03	$1.91	$1.86
Diluted	2.03	1.91	1.85
Cash dividends declared per common share	1.20	1.11	1.07

See Notes to Condensed Financial Statements

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XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2014	2013	2012
Operating activities			
Net cash provided by operating activities	$842,832	$545,177	$815,209
Investing activities			
Capital contributions to subsidiaries	(422,459)	(535,653)	(366,783)
Investments in the utility money pool	(1,148,000)	(1,778,000)	(640,000)
Return of investments in the utility money pool	1,204,000	1,706,000	658,000
Net cash used in investing activities	(366,459)	(607,653)	(348,783)
Financing activities			
(Repayment of) proceeds from short-term borrowings, net	(95,500)	297,000	52,000
Proceeds from issuance of long-term debt	—	447,595	—
Repayment of long-term debt	—	(400,000)	—
Proceeds from issuance of common stock	180,798	231,767	8,050
Repurchase of common stock	—	—	(18,529)
Purchase of common stock for settlement of equity awards	—	—	(23,307)
Dividends paid	(561,411)	(514,042)	(486,757)
Net cash (used in) provided by financing activities	(476,113)	62,320	(468,543)
Net change in cash and cash equivalents	260	(156)	(2,117)
Cash and cash equivalents at beginning of period	446	602	2,719
Cash and cash equivalents at end of period	$706	$446	$602

See Notes to Condensed Financial Statements

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XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in thousands)

	Dec. 31	
	2014	2013
Assets		
Cash and cash equivalents	$706	$446
Accounts receivable from subsidiaries	270,921	240,450
Other current assets	47,424	51,086
Total current assets	319,051	291,982
Investment in subsidiaries	12,206,575	11,613,032
Other assets	114,518	105,073
Total other assets	12,321,093	11,718,105
Total assets	$12,640,144	$12,010,087
Liabilities and Equity		
Dividends payable	$151,720	$139,432
Short-term debt	380,500	476,000
Other current liabilities	65,314	6,954
Total current liabilities	597,534	622,386
Other liabilities	30,227	25,475
Total other liabilities	30,227	25,475
Commitments and contingencies		
Capitalization		
Long-term debt	1,797,901	1,796,276
Common stockholders' equity	10,214,482	9,565,950
Total capitalization	12,012,383	11,362,226
Total liabilities and equity	$12,640,144	$12,010,087

See Notes to Condensed Financial Statements

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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:

(Thousands of Dollars)	2014 Accounts Receivable	2014 Accounts Payable	2013 Accounts Receivable	2013 Accounts Payable
NSP-Minnesota	$79,390	$—	$57,596	$—
NSP-Wisconsin	20,117	—	6,933	—
PSCo	38,646	—	74,739	—
SPS	28,062	—	5,705	—
Xcel Energy Services Inc.	75,954	—	60,138	—
Xcel Energy Ventures Inc.	20,082	—	20,194	—
Other subsidiaries of Xcel Energy Inc.	8,670	—	15,145	—
	$270,921	$—	$240,450	$—

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $857 million, $606 million and $757 million for the years ended Dec. 31, 2014, 2013 and 2012, 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, 2014
Lending limit	$250

Loan outstanding at period end	16	
Average loan outstanding	2	
Maximum loan outstanding	21	
Weighted average interest rate, computed on a daily basis	0.30	%
Weighted average interest rate at end of period	0.45	
Money pool interest income	$—	

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(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013	Year Ended Dec. 31, 2012
Lending limit	$250	$250	$250
Loan outstanding at period end	16	72	—
Average loan outstanding	25.0	88.2	26.1
Maximum loan outstanding	250	243	226
Weighted average interest rate, computed on a daily basis	0.22 %	0.30 %	0.33 %
Weighted average interest rate at end of period	0.45	0.25	N/A
Money pool interest income	$0.1	$0.3	$0.1

See Xcel Energy’s notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

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SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2014, 2013 AND 2012
(amounts in thousands)

	Balance at Jan. 1	Additions Charged to Costs and Expenses	Charged to Other Accounts[(a)]	Deductions from Reserves[(b)(c)]	Balance at Dec. 31
Allowance for bad debts:					
2014	$53,107	$42,765	$14,067	$52,220	$57,719
2013	51,394	37,627	14,469	50,383	53,107
2012	58,565	33,808	16,033	57,012	51,394
NOL and tax credit valuation allowances:					
2014	$3,263	$139	$—	$—	$3,402
2013	3,314	—	—	51	3,263
2012	5,683	32	—	2,401	3,314

(a) Recovery of amounts previously written off as related to allowance for bad debts.

(b) Principally bad debts written off as related to allowance for bad debts.

(c) Reductions to valuation allowances for NOL and tax credit carryforwards primarily due to changes in tax laws, expirations of certain carryforwards and identification of various tax planning strategies.

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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. 20, 2015	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 Ben Fowke	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERESA S. MADDEN Teresa S. Madden	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
* Gail Koziara Boudreaux	Director
* Richard K. Davis	Director
* Albert F. Moreno	Director
* Richard T. O’Brien	Director
* Christopher J. Policinski	Director
* A. Patricia Sampson	Director
* James J. Sheppard	Director
* David A. Westerlund	Director
*	Director

	Kim Williams	
*	Timothy V. Wolf	Director
*By:	/s/ TERESA S. MADDEN Teresa S. Madden	Attorney-in-Fact

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