UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

or

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

Commission file number 001-31387

NORTHERN STATES POWER COMPANY

(Exact name of registrant as specified in its charter)

Minnesota	**41-1967505**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

414 Nicollet Mall, Minneapolis, Minnesota 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: **None**

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller Reporting Company ☐

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

As of Feb. 22, 2016, 1,000,000 shares of common stock, par value $0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm – Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 4, 2016. Such information set forth under such heading is incorporated herein by this reference hereto.

Northern States Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

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This Form 10-K is filed by NSP-Minnesota. NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

PART I

Item l — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
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
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries
Federal and State Regulatory Agencies	
ASLB	Atomic Safety and Licensing Board
CFTC	Commodity Futures Trading 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
NRC	Nuclear Regulatory Commission
PSCW	Public Service Commission of Wisconsin
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
EIR	Environmental improvement rider
EPU	Extended power uprate
FCA	Fuel clause adjustment
GUIC	Gas utility infrastructure cost rider
PGA	Purchased gas adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
SEP	State energy policy
TCR	Transmission cost recovery adjustment
Other Terms and Abbreviations	
AFUDC	Allowance for funds used during construction
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
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CO_2	Carbon dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
EGU	Electric generating unit
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
ISFSI	Independent spent fuel storage installation
ITC	Investment tax credit
JOA	Joint operating agreement
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
MVP	Multi-value project
MYP	Multi-year plan
NAAQS	National Ambient Air Quality Standard
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract.
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOV	Notice of violation
NOx	Nitrogen oxide
NYISO	New York Independent System Operator
O&M	Operating and maintenance
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
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
REC	Renewable energy credit
ROE	Return on equity
RPS	Renewable portfolio standard
RTO	Regional Transmission Organization
SIP	State implementation plan

SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor’s	Standard & Poor’s Ratings Services
TO	Transmission owner
Measurements	
Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

COMPANY OVERVIEW

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is a utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately eight percent of its total KWh sold in 2015. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 88 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2015. Although NSP-Minnesota's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large commercial and industrial electric sales include the following industries: petroleum, coal and food products. For small commercial and industrial 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. Generally, sales to NSP-Wisconsin through the Interchange Agreement account for approximately 10 percent of NSP-Minnesota's consolidated revenues.

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

NSP-Minnesota conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 15 to the consolidated financial statements for further discussion relating to comparative segment revenues, net income and related financial information.

NSP-Minnesota's corporate strategy focuses on four core objectives: improving utility performance; driving operational excellence; delivering what customers want and value; and investing for the future.

ELECTRIC UTILITY OPERATIONS

Public Utility Regulation

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

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

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

- *CIP* — The CIP recovers the costs of conservation and demand-side management programs that help customers save energy.
- *EIR* — The EIR recovers the costs of environmental improvement projects.
- *RDF* — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — The RES recovers the cost of new renewable generation in Minnesota.
- *RER* — The RER recovers the cost of new renewable generation in North Dakota.

- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in electric transmission and distribution costs that facilitate grid modernization.
- *Infrastructure* — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes in South Dakota.

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

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

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

Capacity and Demand

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

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

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

Energy Sources and Related Transmission Initiatives

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Nuclear Power Operations and Waste Disposal

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

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

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

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

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

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

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

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

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

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

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

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

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

Nuclear Geologic Repository - Yucca Mountain Project

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

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

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

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

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

Nuclear Spent Fuel Storage

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

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

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

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

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

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

See Note 12 to the consolidated financial statements for further discussion regarding nuclear related items.

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
NSP System Generating Plants	Cost	Percent	Cost	Percent	Cost	Percent	Average Owned Fuel Cost
2015	$ 2.15	47%	$ 0.83	40%	$ 3.89	13%	$ 1.85
2014	2.23	52	0.89	42	6.27	6	1.94
2013	2.20	49	0.95	40	5.08	11	2.03

(a) Includes refuse-derived fuel and wood.

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

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

Fuel Sources

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

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

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

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

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

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

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

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies, transportation and storage services for power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015 and 2014, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately $310 million and $349 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2016 to 2028.

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

Renewable Energy Sources

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

- Renewable energy comprised 23.3 percent and 24.2 percent of the NSP System's total energy for 2015 and 2014, respectively;
- Wind energy comprised 13.6 percent and 13.7 percent of the total energy for 2015 and 2014, respectively;
- Hydroelectric energy comprised 7.3 percent and 7.8 percent of the total energy for 2015 and 2014, respectively; and
- Biomass and solar power comprised approximately 2.4 percent and 2.7 percent of the total energy for 2015 and 2014, respectively.

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

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

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

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

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

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

Wholesale and Commodity Marketing Operations

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

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 NSP-Minnesota, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of NSP-Minnesota's activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 10 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In March, 2015, FERC upheld the new ROE methodology and denied rehearing. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. FERC is not expected to issue orders in any litigated ROE complaint proceedings until at least mid-2016. See Note 10 to the consolidated financial statements for discussion of the MISO ROE Complaints.

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

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

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

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

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2015	2014	2013
Electric sales (Millions of KWh)			
Residential	9,988	10,317	10,486
Large commercial and industrial	8,921	8,859	8,963
Small commercial and industrial	15,460	15,670	15,577
Public authorities and other	251	264	267
Total retail	34,620	35,110	35,293
Sales for resale	3,008	2,704	1,397
Total energy sold	37,628	37,814	36,690
Number of customers at end of period			
Residential	1,284,986	1,274,182	1,263,575
Large commercial and industrial	551	466	483
Small commercial and industrial	155,039	153,988	152,769
Public authorities and other	7,122	7,015	6,869
Total retail	1,447,698	1,435,651	1,423,696
Wholesale	13	14	12
Total customers	1,447,711	1,435,665	1,423,708
Electric revenues (Thousands of Dollars)			
Residential	$ 1,238,362	$ 1,257,366	$ 1,244,712
Large commercial and industrial	669,774	674,210	686,970
Small commercial and industrial	1,445,897	1,454,153	1,410,083
Public authorities and other	34,408	35,335	36,207
Total retail	3,388,441	3,421,064	3,377,972
Wholesale	69,918	92,326	47,511
Interchange revenues from NSP-Wisconsin	473,099	474,542	458,633
Other electric revenues	252,257	214,424	178,324
Total electric revenues	$ 4,183,715	$ 4,202,356	$ 4,062,440
KWh sales per retail customer	23,914	24,456	24,790
Revenue per retail customer	$ 2,341	$ 2,383	$ 2,373
Residential revenue per KWh	12.40 ¢	12.19 ¢	11.87 ¢
Large commercial and industrial revenue per KWh	7.51	7.61	7.66
Small commercial and industrial revenue per KWh	9.35	9.28	9.05
Total retail revenue per KWh	9.79	9.74	9.57
Wholesale revenue per KWh	2.32	3.41	3.40

Energy Source Statistics

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

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

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

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of NSP-Minnesota are uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2015, average annual sales to the typical residential customer declined 20 percent, while sales to the typical small C&I customer declined two 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 NSP-Minnesota 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. NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the GUIC rider.

Public Utility Regulation

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

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

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

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

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 774,044 MMBtu, which occurred on Jan. 12, 2015 and 752,931 MMBtu, which occurred on Jan. 2, 2014.

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

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 219,200 MMBtu of natural gas per day, or approximately 27 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. In October 2015, the MPUC approved NSP-Minnesota's contract demand levels for the 2014 through 2015 heating season. Demand levels filed with the MPUC in 2015 for the 2015 through 2016 heating season were approved in February 2016.

Natural Gas Supply and Costs

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

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

2015	$ 4.07
2014	6.17
2013	4.53

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

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

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

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

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

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2015	**2014**	**2013**
Natural gas deliveries (Thousands of MMBtu)			
Residential	36,810	45,044	42,446
Commercial and industrial	38,571	44,815	42,459
Total retail	75,381	89,859	84,905
Transportation and other	11,648	11,265	11,076
Total deliveries	87,029	101,124	95,981
Number of customers at end of period			
Residential	460,949	456,191	450,958
Commercial and industrial	43,015	42,504	41,929
Total retail	503,964	498,695	492,887
Transportation and other	20	24	24
Total customers	503,984	498,719	492,911
Natural gas revenues (Thousands of Dollars)			
Residential	$ 302,696	$ 412,723	$ 329,810
Commercial and industrial	234,201	331,069	249,620
Total retail	536,897	743,792	579,430
Transportation and other	8,238	13,903	11,587
Total natural gas revenues	$ 545,135	$ 757,695	$ 591,017
MMBtu sales per retail customer	149.58	180.19	172.26
Revenue per retail customer	$ 1,065	$ 1,491	$ 1,176
Residential revenue per MMBtu	8.22	9.16	7.77
Commercial and industrial revenue per MMBtu	6.07	7.39	5.88
Transportation and other revenue per MMBtu	0.71	1.23	1.05

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, NSP-Minnesota'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

NSP-Minnesota is a vertically integrated utility, subject to traditional cost-of-service regulation. However, NSP-Minnesota is subject to different public policies that promote competition and the development of energy markets. NSP-Minnesota's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with solar generation (typically rooftop solar or solar gardens) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states, including Minnesota, 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 NSP-Minnesota's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, NSP-Minnesota and its wholesale customers can purchase generation resources from competing wholesale suppliers and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions, including the MPUC, 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. NSP-Minnesota has franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. While facing these challenges, NSP-Minnesota believes its rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

NSP-Minnesota'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. NSP-Minnesota has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. NSP-Minnesota'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 NSP-Minnesota's operations. See Notes 10 and 11 to the consolidated financial statements for further discussion.

There are significant present and future environmental regulations to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. NSP-Minnesota 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.

EMPLOYEES

As of Dec. 31, 2015, NSP-Minnesota had 3,623 full-time employees and 11 part-time employees, of which 2,248 were covered under collective-bargaining agreements. See Note 7 to the consolidated financial statements for further discussion.

Item 1A — Risk Factors

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

Oversight of Risk and Related Processes

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

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economies and the environment when identifying, assessing, managing and mitigating risk. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing our 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, we have developed a robust compliance program and promote 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, we manage and further mitigate risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of internal corporate areas such as internal audit, the corporate controller and legal services.

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

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

Risks Associated with Our Business

Environmental Risks

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

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

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

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

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

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

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

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

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

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

Financial Risks

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

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The state utility commissions 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 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. We provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of our costs incurred in a test year. Thus, the rates we are allowed to charge may or may not match our 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 of our costs to have been prudent, which could result in cost disallowances, or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements and there is no assurance that regulators would allow full recovery of all remaining costs. Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including debt payments.

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 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, we may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

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

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

We are subject to credit risks.

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

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

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

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

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

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

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

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

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

Operational Risks

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

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

If we encounter market supply shortages or our suppliers are otherwise unable to meet their contractual obligations, we may be unable to fulfill our contractual obligations to our customers at previously anticipated costs. Therefore, a significant disruption could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments could have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues depends on our 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.

We are subject to the risks of nuclear generation.

Our two nuclear stations, PI and Monticello, subject us to the risks of nuclear generation, which include:

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. For example, similar to pensions, interest rate and other assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

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

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

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

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

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

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

Our natural gas transmission and distribution activities include a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. We maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material effect on our financial position and results of operations. For our natural gas transmission or distribution lines located near populated areas, the level of potential damages resulting from these risks is greater.

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

As we are a subsidiary of Xcel Energy Inc., we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If Xcel Energy Inc. were to become obligated to make payments under various guarantees and bond indemnities or to fund its other contingent liabilities, or if either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s credit rating below investment grade, Xcel Energy Inc. may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures. If either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2015, Xcel Energy Inc. and its utility subsidiaries had approximately $12.5 billion of long-term debt and $1.5 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees. As of Dec. 31, 2015, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $12.5 million and exposure of $0.1 million. Xcel Energy also had additional guarantees of $41.3 million at Dec. 31, 2015 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. In 2015, 2014 and 2013 we paid $259.1 million, $259.5 million and $235.5 million of dividends to Xcel Energy Inc., respectively. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for NSP-Minnesota is imposed by our state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio. See Item 5 for further discussion on dividend limitations.

Public Policy Risks

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

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

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

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

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

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

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

Increased risks of regulatory penalties could negatively impact our business.

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

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

Macroeconomic Risks

Economic conditions impact our business.

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

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

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

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

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities. Any such disruption could result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. In addition, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection. In addition, we may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

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

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

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

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

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

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

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

Rising energy prices could negatively impact our business.

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

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

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

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota is subject to the lien of its first mortgage bond indenture.

Electric Utility Generating Stations:

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

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

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

(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

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

Conductor Miles	
500 KV	2,917
345 KV	8,425
230 KV	2,157
161 KV	395
115 KV	7,502
Less than 115 KV	84,074

NSP-Minnesota had 349 electric utility transmission and distribution substations at Dec. 31, 2015.

Natural gas utility mains at Dec. 31, 2015:

Miles	
Transmission	136
Distribution	10,084

Item 3 — Legal Proceedings

NSP-Minnesota 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 11 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1 and Note 10 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

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

NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than $1.7 billion and $1.6 billion in additional cash dividends on common stock at Dec. 31, 2015 and 2014, respectively.

In addition, NSP-Minnesota has dividend restrictions imposed by FERC rules and state regulatory commissions:

- 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.
- The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-capitalization ratio was 52.1 percent at Dec. 31, 2015 and $967 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was $9.9 billion at Dec. 31, 2015, which did not exceed the limits imposed by the commissions of $10.5 billion.

See Note 4 to the consolidated financial statements for further discussion of NSP-Minnesota's dividend policy.

The dividends declared during 2015 and 2014 were as follows:

(Thousands of Dollars)	2015	2014
First quarter	$ 55,869	$ 59,740
Second quarter	65,087	73,750
Third quarter	60,382	67,210
Fourth quarter	73,498	77,802

Item 6 — Selected Financial Data

This is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

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

Discussion of financial condition and liquidity for NSP-Minnesota is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management's narrative analysis and the results of operations for the current year as set forth in general instructions I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on NSP-Minnesota'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 related notes to the consolidated financial statements.

Forward-Looking Statements

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

Results of Operations

NSP-Minnesota’s net income was approximately $356.8 million for 2015, compared with approximately $404.9 million for 2014. The impact of the Monticello LCM/EPU project loss, unfavorable weather, sales decline, higher depreciation, increased interest charges, property taxes and lower AFUDC were partially offset by higher revenue attributable to electric rate increases in Minnesota, North Dakota and South Dakota and lower O&M expenses. See Note 10 to the consolidated financial statements for further discussion of the Monticello LCM/EPU project loss.

Electric Revenues and Margin

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

(Millions of Dollars)	2015	2014
Electric revenues	$ 4,184	$ 4,202
Electric fuel and purchased power	(1,584)	(1,676)
Electric margin	$ 2,600	$ 2,526

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

Electric Revenues

(Millions of Dollars)	2015 vs. 2014
Fuel and purchased power cost recovery	$ (83)
Conservation program revenues (offset by expenses)	(56)
Trading	(26)
Estimated impact of weather	(25)
Retail rate increases [a]	116
Transmission revenue	25
Non-fuel riders [b]	23
Other, net	8
Total decrease in electric revenues	$ (18)

Electric Margin

(Millions of Dollars)	2015 vs. 2014
Retail rate increases [a]	$ 116
Non-fuel riders [b]	23
Conservation program revenues (offset by expenses)	(56)
Estimated impact of weather	(25)
Other, net	16
Total increase in electric margin	$ 74

[a] The retail rate increases are due to rate proceedings in Minnesota, South Dakota and North Dakota. See Note 10 to the consolidated financial statements.
[b] Primarily related to the TCR rider in Minnesota.

Natural Gas Revenues and Margin

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

(Millions of Dollars)	2015	2014
Natural gas revenues	$ 545	$ 758
Cost of natural gas sold and transported	(332)	(532)
Natural gas margin	$ 213	$ 226

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

Natural Gas Revenues

(Millions of Dollars)	2015 vs. 2014
Purchased natural gas adjustment clause recovery	$ (193)
Estimated impact of weather	(18)
Conservation program revenues (offset by expenses)	(11)
Infrastructure rider	12
Other, net	(3)
Total decrease in natural gas revenues	$ (213)

Natural Gas Margin

(Millions of Dollars)	2015 vs. 2014
Estimated impact of weather	$ (18)
Conservation program revenues (offset by expenses)	(11)
Infrastructure rider	12
Other, net	4
Total decrease in natural gas margin	$ (13)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $11.3 million, or 0.9 percent, for 2015 compared with 2014. The following table summarizes the changes in O&M expenses for the year ended Dec. 31:

(Millions of Dollars)	2015 vs. 2014
Nuclear plant operations and amortization	$ (22)
Plant generation costs	(6)
Transmission costs	(2)
Interchange billings with NSP-Wisconsin	16
Labor and contract labor	4
Electric and gas distribution costs	4
Other, net	(5)
Total decrease in O&M expenses	$ (11)

Changes in annual O&M expenses were primarily due to the following:

- Nuclear expense decreased primarily driven by operational efficiencies and lower amortization of prior outages; and
- Interchange billings with NSP-Wisconsin increased due to the timing of transmission projects.

Conservation Program Expenses — Conservation program expenses decreased $67.2 million for 2015 compared with 2014. The decrease was primarily attributable to lower electric and gas recovery rates. Lower conservation and DSM program expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization expense increased $68.5 million, or 16.7 percent, for 2015 compared with 2014. The increase was primarily attributable to lower amortization of the excess depreciation reserve in Minnesota and capital investments, partially offset by Minnesota's amortization of the DOE settlement.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $7.8 million, or 3.5 percent, for 2015 compared with 2014. The increase was primarily due to higher property taxes in Minnesota.

AFUDC, Equity and Debt — AFUDC increased $5.0 million for 2015 compared with 2014. The increase is primarily related to construction of the Courtenay Wind Farm.

Interest Charges — Interest charges increased $9.1 million, or 4.6 percent, for 2015 compared with 2014. The increase was primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $17.4 million for 2015 compared with 2014. The decrease in income tax expense was primarily due to lower pre-tax earnings in 2015 and an increase in permanent plant-related adjustments (e.g., AFUDC-equity) in 2015. This was partially offset by a higher tax benefit for a carryback claim in 2014. The ETR was 33.6 percent for 2015 compared with 32.9 percent for 2014. See Note 6 to the consolidated financial statements for further discussion.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

Derivatives, Risk Management and Market Risk

NSP-Minnesota is 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 9 to the consolidated financial statements for further discussion of market risks associated with derivatives.

NSP-Minnesota 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 NSP-Minnesota expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose NSP-Minnesota to some credit and nonperformance risk.

Though no material non-performance risk currently exists with the counterparties to NSP-Minnesota'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 NSP-Minnesota's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — NSP-Minnesota is exposed to commodity price risk in its electric and natural gas operations. Commodity price risk is managed by entering into short- and long-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. NSP-Minnesota'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 — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

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

		Futures / Forwards				
(Thousands of Dollars)	**Source of Fair Value**	**Maturity Less Than 1 Year**	**Maturity 1 to 3 Years**	**Maturity 4 to 5 Years**	**Maturity Greater Than 5 Years**	**Total Futures/ Forwards Fair Value**
NSP-Minnesota	1	$ 2,699	$ 5,959	$ 1,575	$ —	$ 10,233
	2	695	—	—	—	695
		$ 3,394	$ 5,959	$ 1,575	$ —	$ 10,928

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

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

(Thousands of Dollars)	**2015**	**2014**
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 21,811	$ 30,196
Contracts realized or settled during the period	(3,592)	(12,198)
Commodity trading contract additions and changes during the period	(7,291)	3,813
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 10,928	$ 21,811

At Dec. 31, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.4 million. At Dec. 31, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.9 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.9 million.

NSP-Minnesota's wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

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

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

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

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

At Dec. 31, 2015 and 2014, a 100-basis-point change in the benchmark rate on NSP-Minnesota's variable rate debt would impact annual pretax interest expense by approximately $2.2 million and $1.4 million, respectively. See Note 9 to the consolidated financial statements for a discussion of NSP-Minnesota's interest rate derivatives.

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

Credit Risk — NSP-Minnesota is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. NSP-Minnesota maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $5.6 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $6.4 million. At Dec. 31, 2014, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $3.5 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $11.9 million.

NSP-Minnesota conducts standard credit reviews for all counterparties. NSP-Minnesota 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 financial markets could increase NSP-Minnesota's credit risk.

Fair Value Measurements

NSP-Minnesota 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 9 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 — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2015. NSP-Minnesota also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2015.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 0.8 percent and 2.4 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2015.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $13.7 million and $0.7 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2015.

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

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

Item 8 — Financial Statements and Supplementary Data

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

See Note 17 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of NSP-Minnesota is responsible for establishing and maintaining adequate internal control over financial reporting. NSP-Minnesota's internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and NSP-Minnesota'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.

NSP-Minnesota management assessed the effectiveness of NSP-Minnesota's internal control over financial reporting as of Dec. 31, 2015. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013)*. Based on our assessment, we believe that, as of Dec. 31, 2015, NSP-Minnesota's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE	/s/ TERESA S. MADDEN
Ben Fowke	Teresa S. Madden
Chairman and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2016	Feb. 22, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Northern States Power Company, a Minnesota corporation

We have audited the accompanying consolidated balance sheets and statements of capitalization of Northern States Power Company, a Minnesota corporation, and subsidiaries (the “Company”) as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholder’s equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Northern States Power Company, a Minnesota corporation, and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2016

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating revenues			
Electric, non-affiliates	$ 3,710,616	$ 3,727,815	$ 3,603,807
Electric, affiliates	473,099	474,542	458,633
Natural gas	545,135	757,695	591,017
Other	27,956	28,473	26,153
Total operating revenues	4,756,806	4,988,525	4,679,610
Operating expenses			
Electric fuel and purchased power	1,583,620	1,676,474	1,683,977
Cost of natural gas sold and transported	331,982	532,475	380,058
Cost of sales — other	18,243	17,371	16,154
Operating and maintenance expenses	1,212,507	1,223,829	1,171,855
Conservation program expenses	70,938	138,105	96,635
Depreciation and amortization	479,342	410,840	414,588
Taxes (other than income taxes)	229,602	221,838	206,741
Loss on Monticello life cycle management/extended power uprate project	124,226	—	—
Total operating expenses	4,050,460	4,220,932	3,970,008
Operating income	706,346	767,593	709,602
Other income (expense), net	446	580	(653)
Allowance for funds used during construction — equity	26,819	23,788	40,064
Interest charges and financing costs			
Interest charges — includes other financing costs of $6,710, $6,511 and $6,337 respectively	208,763	199,667	191,889
Allowance for funds used during construction — debt	(12,725)	(10,711)	(18,079)
Total interest charges and financing costs	196,038	188,956	173,810
Income before income taxes	537,573	603,005	575,203
Income taxes	180,734	198,090	181,857
Net income	$ 356,839	$ 404,915	$ 393,346

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2015	**2014**	**2013**
Net income	$ 356,839	$ 404,915	$ 393,346
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical benefits (losses) gains arising during the period, net of tax of $(731), $111 and $294, respectively	(1,061)	161	423
Amortization of (gains) losses included in net periodic benefit cost, net of tax of $(15), $16 and $63, respectively	(25)	22	91
	(1,086)	183	514
Derivative instruments:			
Net fair value (decrease) increase, net of tax of $(27), $(61) and $10, respectively	(39)	(89)	5
Reclassification of losses to net income, net of tax of $600, $568 and $560, respectively	858	789	779
	819	700	784
Marketable securities:			
Net fair value increase, net of tax of $0, $22 and $120, respectively	—	32	172
Other comprehensive (loss) income	(267)	915	1,470
Comprehensive income	$ 356,572	$ 405,830	$ 394,816

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating activities			
Net income	$ 356,839	$ 404,915	$ 393,346
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	485,121	416,380	419,852
Nuclear fuel amortization	106,424	114,542	98,089
Deferred income taxes	206,836	167,471	168,444
Amortization of investment tax credits	(1,729)	(1,735)	(1,813)
Allowance for equity funds used during construction	(26,819)	(23,788)	(40,064)
Provision for bad debts	14,420	17,193	13,418
Loss on Monticello life cycle management/extended power uprate project	124,226	—	—
Net realized and unrealized hedging and derivative transactions	16,075	5,023	(4,175)
Changes in operating assets and liabilities:			
Accounts receivable	66,539	(104,655)	3,220
Accrued unbilled revenues	24,485	3,825	(25,748)
Inventories	(53,468)	(10,285)	(19,404)
Other current assets	23,303	(33,284)	22,316
Accounts payable	(39,696)	(50,569)	68,003
Net regulatory assets and liabilities	(6,459)	101,826	10,703
Other current liabilities	77,998	118,576	36,709
Pension and other employee benefit obligations	(22,265)	(41,924)	(59,953)
Change in other noncurrent assets	(219)	34,571	(9,599)
Change in other noncurrent liabilities	(31,764)	(5,985)	(4,463)
Net cash provided by operating activities	1,319,847	1,112,097	1,068,881
Investing activities			
Utility capital/construction expenditures	(1,854,878)	(1,241,940)	(1,548,952)
Allowance for equity funds used during construction	26,819	23,788	40,064
Proceeds from insurance recoveries	27,237	6,000	90,000
Purchases of investments in external decommissioning fund	(1,257,924)	(595,569)	(1,481,881)
Proceeds from the sale of investments in external decommissioning fund	1,236,873	588,430	1,461,291
Investments in utility money pool arrangement	(385,900)	(432,000)	(29,000)
Repayments from utility money pool arrangement	385,900	432,000	29,000
Other, net	(2,662)	(3,066)	(3,716)
Net cash used in investing activities	(1,824,535)	(1,222,357)	(1,443,194)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	81,000	11,000	(90,000)
Borrowings under utility money pool arrangement	294,500	340,000	997,000
Repayments under utility money pool arrangement	(294,500)	(374,000)	(963,000)
Proceeds from issuance of long-term debt	587,545	295,337	394,788
Repayments of long-term debt, including reacquisition premiums	(250,013)	—	—
Capital contributions from parent	347,304	95,051	285,102
Dividends paid to parent	(259,140)	(259,451)	(235,499)
Net cash provided by financing activities	506,696	107,937	388,391
Net change in cash and cash equivalents	2,008	(2,323)	14,078
Cash and cash equivalents at beginning of period	40,597	42,920	28,842
Cash and cash equivalents at end of period	$ 42,605	$ 40,597	$ 42,920
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (185,170)	$ (182,603)	$ (166,515)
Cash received (paid) for income taxes, net	53,243	(33,586)	2,064
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 111,675	$ 186,068	$ 234,686

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31 2015	Dec. 31 2014
Assets		
Current assets		
Cash and cash equivalents	$ 42,605	$ 40,597
Accounts receivable, net	292,806	367,696
Accounts receivable from affiliates	32,850	24,067
Accrued unbilled revenues	227,102	251,587
Inventories	343,916	290,287
Regulatory assets	187,793	235,487
Derivative instruments	18,941	60,164
Deferred income taxes	15,577	76,016
Prepayments and other	89,559	142,443
Total current assets	1,251,149	1,488,344
Property, plant and equipment, net	12,807,338	11,661,620
Other assets		
Nuclear decommissioning fund and other investments	1,758,208	1,735,316
Regulatory assets	1,159,217	1,051,834
Derivative instruments	22,334	15,434
Other	39,086	34,768
Total other assets	2,978,845	2,837,352
Total assets	$ 17,037,332	$ 15,987,316
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 11	$ 250,013
Short-term debt	223,000	142,000
Accounts payable	350,660	470,507
Accounts payable to affiliates	59,785	50,545
Regulatory liabilities	43,920	171,608
Taxes accrued	225,361	198,509
Accrued interest	66,979	61,339
Dividends payable to parent	73,498	77,802
Derivative instruments	17,211	12,294
Customer deposits	94,388	44,276
Other	177,795	172,939
Total current liabilities	1,332,608	1,651,832
Deferred credits and other liabilities		
Deferred income taxes	2,572,087	2,429,143
Deferred investment tax credits	25,838	27,567
Regulatory liabilities	491,887	451,783
Asset retirement obligations	2,331,092	2,186,174
Derivative instruments	128,213	135,036
Pension and employee benefit obligations	339,663	340,774
Other	114,768	123,165
Total deferred credits and other liabilities	6,003,548	5,693,642
Commitments and contingencies		
Capitalization		
Long-term debt	4,534,111	3,938,669
Common stock — 5,000,000 shares authorized of $0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2015 and 2014, respectively	10	10
Additional paid in capital	3,323,810	2,961,654
Retained earnings	1,864,326	1,762,323
Accumulated other comprehensive loss	(21,081)	(20,814)
Total common stockholder's equity	5,167,065	4,703,173
Total liabilities and equity	$ 17,037,332	$ 15,987,316

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in thousands, except share data)

	Common Stock					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2012	1,000,000	$ 10	$ 2,581,501	$ 1,478,057	$ (23,199)	$ 4,036,369
Net income				393,346		393,346
Other comprehensive income					1,470	1,470
Common dividends declared to parent				(235,493)		(235,493)
Contribution of capital by parent			285,102			285,102
Balance at Dec. 31, 2013	1,000,000	$ 10	$ 2,866,603	$ 1,635,910	$ (21,729)	$ 4,480,794
Net income				404,915		404,915
Other comprehensive income					915	915
Common dividends declared to parent				(278,502)		(278,502)
Contribution of capital by parent			95,051			95,051
Balance at Dec. 31, 2014	1,000,000	$ 10	$ 2,961,654	$ 1,762,323	$ (20,814)	$ 4,703,173
Net income				356,839		356,839
Other comprehensive loss					(267)	(267)
Common dividends declared to parent				(254,836)		(254,836)
Contribution of capital by parent			362,156			362,156
Balance at Dec. 31, 2015	1,000,000	$ 10	$ 3,323,810	$ 1,864,326	$ (21,081)	$ 5,167,065

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
Long-Term Debt		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	$ —	$ 250,000
March 1, 2018, 5.25%	500,000	500,000
Aug. 15, 2020, 2.2%	300,000	—
Aug. 15, 2022, 2.15%	300,000	300,000
May 15, 2023, 2.6%	400,000	400,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	300,000
Aug. 15, 2040, 4.85%	250,000	250,000
Aug. 15, 2042, 3.4%	500,000	500,000
May 15, 2044, 4.125%	300,000	300,000
Aug. 15, 2045, 4.0%	300,000	—
Other	33	47
Unamortized discount	(15,911)	(11,365)
Total	4,534,122	4,188,682
Less current maturities	11	250,013
Total long-term debt	$ 4,534,111	$ 3,938,669
Common Stockholder's Equity		
Common stock — 5,000,000 shares authorized of $0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2015 and 2014, respectively	$ 10	$ 10
Additional paid in capital	3,323,810	2,961,654
Retained earnings	1,864,326	1,762,323
Accumulated other comprehensive loss	(21,081)	(20,814)
Total common stockholder's equity	$ 5,167,065	$ 4,703,173

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — NSP-Minnesota is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota's consolidated financial statements and disclosures are presented in accordance with GAAP. All of NSP-Minnesota's 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 — NSP-Minnesota's consolidated financial statements include its wholly-owned subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. NSP-Minnesota has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. NSP-Minnesota's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets and NSP-Minnesota'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 and transmission facilities and related ownership percentages.

NSP-Minnesota 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 NSP-Minnesota has a variable interest and if NSP-Minnesota is the primary beneficiary. NSP-Minnesota 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 NSP-Minnesota is a variable interest entity's primary beneficiary. See Note 11 for further discussion of variable interest entities.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Minnesota 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 — NSP-Minnesota accounts for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If restructuring or other changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's financial condition, results of operations and cash flows. See Note 13 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. NSP-Minnesota presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO. NSP-Minnesota recognizes sales to both native load and other end use customers on a gross basis. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

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

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

Conservation Programs — NSP-Minnesota has implemented programs in its retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas system. These programs include a wide variety of programs including, but not limited to, commercial process efficiency and lighting upgrades, as well as incentives for participation in air-conditioning interruption.

The costs incurred for 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.

NSP-Minnesota's 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 NSP-Minnesota's achievement of energy conservation goals and to compensate for related lost sales margin. NSP-Minnesota recognizes regulatory assets to reflect the amount of costs or earned incentives that have not yet been collected from customers.

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

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 10 for a discussion of the loss recognized related to the Monticello LCM/EPU project. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota 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 2.9, 2.5 and 2.9 percent for the years ended Dec. 31, 2015, 2014 and 2013, respectively.

Leases — NSP-Minnesota 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 11 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 nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota'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, including certain wind and transmission projects, the MPUC has approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

AROs — NSP-Minnesota accounts 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. NSP-Minnesota also recovers 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 11 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota's most recent triennial nuclear decommissioning studies were approved by the MPUC in October 2015. These studies reflect NSP-Minnesota's plans, under the current operating licenses, 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 12 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 9 for further discussion of the nuclear decommissioning fund.

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

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

Income Taxes — NSP-Minnesota 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. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

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

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize only applies to federal ITCs. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 13.

NSP-Minnesota 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. NSP-Minnesota 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.

NSP-Minnesota 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, including NSP-Minnesota, 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 which are recorded directly in equity by the 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 — NSP-Minnesota 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. NSP-Minnesota is 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 9.

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 — NSP-Minnesota 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.

NSP-Minnesota 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 9 for further discussion of NSP-Minnesota'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.

Pursuant to the JOA approved by the FERC, some of NSP-Minnesota's commodity trading margins are apportioned to PSCo and SPS. Commodity trading activities are not associated with energy produced from NSP-Minnesota'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. For further information, see Note 9.

Fair Value Measurements — NSP-Minnesota 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, NSP-Minnesota 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. For further information, see Note 9.

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

Accounts Receivable and Allowance for Bad Debts **—** Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota 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. NSP-Minnesota acquires 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.

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

Emission Allowances — Emission allowances, including the annual SO_2 and NOx emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. NSP-Minnesota 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 NSP-Minnesota is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost. Any future costs of restoring sites where operation may be extended 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 11 for further discussion of environmental costs.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota 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 regulatory recovery mechanisms, 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 7 for further discussion of benefit plans and other postretirement benefits.

Guarantees — NSP-Minnesota 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 NSP-Minnesota is released from risk under the guarantee. See Note 11 for specific details of issued guarantees.

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

2. Accounting Pronouncements

Recently Issued

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

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

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

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

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

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

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	$ 313,556	$ 390,633
Less allowance for bad debts	(20,750)	(22,937)
	$ 292,806	$ 367,696

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	$ 200,888	$ 157,376
Fuel	104,499	77,139
Natural gas	38,529	55,772
	$ 343,916	$ 290,287

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	$ 16,256,887	$ 14,831,286
Natural gas plant	1,248,408	1,177,021
Common and other property	624,409	568,287
CWIP	545,535	706,979
Total property, plant and equipment	18,675,239	17,283,573
Less accumulated depreciation	(6,251,498)	(6,012,145)
Nuclear fuel	2,447,251	2,347,422
Less accumulated amortization	(2,063,654)	(1,957,230)
	$ 12,807,338	$ 11,661,620

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. 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. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	$ 250
Amount outstanding at period end	—
Average amount outstanding	5
Maximum amount outstanding	45
Weighted average interest rate, computed on a daily basis	0.48%
Weighted average interest rate at period end	N/A

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2015	Twelve Months Ended Dec. 31, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit	$ 250	$ 250	$ 250
Amount outstanding at period end	—	—	34
Average amount outstanding	5	12	42
Maximum amount outstanding	69	150	211
Weighted average interest rate, computed on a daily basis	0.53%	0.21%	0.30%
Weighted average interest rate at period end	N/A	N/A	0.25

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	$ 500
Amount outstanding at period end	223
Average amount outstanding	85
Maximum amount outstanding	322
Weighted average interest rate, computed on a daily basis	0.54%
Weighted average interest rate at period end	0.72

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2015	Twelve Months Ended Dec. 31, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit	$ 500	$ 500	$ 500
Amount outstanding at period end	223	142	131
Average amount outstanding	96	111	97
Maximum amount outstanding	327	397	347
Weighted average interest rate, computed on a daily basis	0.43%	0.26%	0.34%
Weighted average interest rate at end of period	0.72	0.53	0.25

Letters of Credit — NSP-Minnesota uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2015 and 2014, there were $18 million and $24 million of letters of credit outstanding, respectively, under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Credit Agreement — NSP-Minnesota has a five-year credit agreement with a syndicate of banks. The total size of the credit facility is $500 million and the credit facility matures in October 2019.

NSP-Minnesota has the right to request an extension of the termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

Other features of NSP-Minnesota's credit facility include:

- NSP-Minnesota may increase its credit facility by up to $100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent at both Dec. 31, 2015 and 2014. If NSP-Minnesota does 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 credit facility has a cross-default provision that provides NSP-Minnesota will be in default on its borrowings under the facility if NSP-Minnesota or any of its subsidiaries whose total assets exceed 15 percent of NSP-Minnesota's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding $75 million.
- NSP-Minnesota was in compliance with all financial covenants on its debt agreements as of Dec. 31, 2015 and 2014.
- The interest rates under the line of credit are based on Eurodollar borrowing margins ranging from 87.5 to 175 basis points per year based on the applicable long-term credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 7.5 to 27.5 basis points per year.

At Dec. 31, 2015, NSP-Minnesota had the following committed credit facility available (in millions):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 241	$ 259

(a) This credit facility matures in October 2019.

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the credit facility outstanding at Dec. 31, 2015 and 2014.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota is subject to the lien of its first mortgage indenture. 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.

In 2015, NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045. In 2014, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044.

During the next five years, NSP-Minnesota has long-term debt maturities of $500 million and $300 million due in 2018 and 2020, respectively.

Deferred Financing Costs — Other assets included deferred financing costs of approximately $37.7 million and $33.6 million, net of amortization, at Dec. 31, 2015 and 2014, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

Dividend and Other Capital-Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than $1.7 billion and $1.6 billion in additional cash dividends on common stock at Dec. 31, 2015 and 2014, respectively.

The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2015 and $967 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was $9.9 billion at Dec. 31, 2015, which did not exceed the limits imposed by the commissions of $10.5 billion.

5. Joint Ownership of Generation and Transmission Facilities

Following are the investments by NSP-Minnesota in jointly owned generation and transmission facilities and the related ownership percentages as of Dec. 31, 2015:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
Electric Generation:				
Sherco Unit 3	$ 590,048	$ 386,675	$ 4,984	59%
Sherco Common Facilities Units 1, 2 and 3	145,825	93,583	47	80
Sherco Substation	4,790	3,054	—	59
Electric Transmission:				
Grand Meadow Line and Substation	9,248	1,451	—	50
CapX2020	947,674	107,985	68,834	51
Total	$ 1,697,585	$ 592,748	$ 73,865	

NSP-Minnesota has approximately 517 MW of jointly owned generating capacity. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

Consolidated Appropriations Act, 2016 - In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

- Immediate expensing, or "bonus depreciation," of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. Additionally, some longer production period property placed in service in 2020 will be eligible for bonus depreciation;
- PTCs at 100 percent of the credit rate ($0.023 per KWh) for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;
- ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- R&E credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment.

Tax Increase Prevention Act of 2014 — In 2014, the Tax Increase Prevention Act (TIPA) was signed into law. The TIPA provides for the following:

- The R&E credit was extended for 2014;
- PTCs were extended for projects that began construction before the end of 2014 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2014. Additionally, some longer production period property placed in service in 2015 is also eligible for 50 percent bonus depreciation.

The accounting related to the TIPA was recorded beginning in the fourth quarter of 2014 because a change in tax law is accounted for in the period of enactment.

American Taxpayer Relief Act of 2012 — In 2013, the American Taxpayer Relief Act (ATRA) was signed into law. The ATRA provided for the following:

- The top tax rate for dividends increased from 15 percent to 20 percent. The 20 percent dividend rate is now consistent with the tax rates for capital gains;
- The R&E credit was extended for 2012 and 2013;
- PTCs were extended for projects that began construction before the end of 2013 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2013. Additionally, some longer production period property placed in service in 2014 is also eligible for 50 percent bonus depreciation.

The accounting related to the ATRA, including the provisions related to 2012, was recorded beginning in the first quarter of 2013 because a change in tax law is accounted for in the period of enactment.

Federal Tax Loss Carryback Claims — In 2012, 2013, 2014 and 2015, NSP-Minnesota identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, NSP-Minnesota recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. In the third quarter of 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $14 million of income tax expense for the 2009 through 2011 and 2013 claims, the recently filed 2014 claim, and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals); however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009 through 2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the Appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Dec. 31, 2015, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2015, NSP-Minnesota's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

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

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	$ 20.1	$ 12.2
Unrecognized tax benefit — Temporary tax positions	35.3	18.2
Total unrecognized tax benefit	$ 55.4	$ 30.4

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

(Millions of Dollars)	2015	2014	2013
Balance at Jan. 1	$ 30.4	$ 25.2	$ 19.5
Additions based on tax positions related to the current year	14.0	10.3	8.1
Reductions based on tax positions related to the current year	(2.1)	(1.2)	—
Additions for tax positions of prior years	14.0	8.9	11.6
Reductions for tax positions of prior years	(0.9)	(4.2)	(1.9)
Settlements with taxing authorities	—	(8.6)	(12.1)
Balance at Dec. 31	$ 55.4	$ 30.4	$ 25.2

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	$ (15.2)	$ (10.8)

It is reasonably possible that NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals and audit progress and state audits resume. As the IRS Appeals and audit progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $32 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Dec. 31, 2015, 2014 and 2013 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2015, 2014 or 2013.

Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2015	2014
Federal NOL carryforward	$ 1,088	$ 598
Federal tax credit carryforwards	167	137
State NOL carryforwards	273	44
State tax credit carryforwards, net of federal detriment [(a)]	32	3
Valuation allowances for state credit carryforwards, net of federal detriment [(b)]	(25)	—

(a) State tax credit carryforwards are net of federal detriment of $17 million and $2 million as of Dec. 31, 2015 and 2014, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $13 million as of Dec. 31, 2015.

The federal carryforward periods expire between 2021 and 2035. The state carryforward periods expire between 2017 and 2035.

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

	2015	2014	2013
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
Tax credits recognized, net of federal income tax expense	(6.3)	(5.3)	(5.3)
NOL carryback	(0.9)	(2.3)	(2.0)
Regulatory differences — utility plant items	(1.7)	(0.2)	(1.8)
State income taxes, net of federal income tax benefit	5.9	5.8	5.6
Change in unrecognized tax benefits	1.5	0.6	1.0
Other, net	0.1	(0.7)	(0.9)
Effective income tax rate	33.6%	32.9%	31.6%

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

(Thousands of Dollars)	2015	2014	2013
Current federal tax (benefit)	$ (41,031)	$ (124)	$ (6,181)
Current state tax (benefit) expense	(3,974)	25,650	11,197
Current change in unrecognized tax expense	20,632	6,828	10,210
Deferred federal tax expense	167,486	143,295	135,539
Deferred state tax expense	52,107	27,256	37,381
Deferred change in unrecognized tax (benefit)	(12,757)	(3,080)	(4,476)
Deferred investment tax credits	(1,729)	(1,735)	(1,813)
Total income tax expense	$ 180,734	$ 198,090	$ 181,857

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

(Thousands of Dollars)	2015	2014	2013
Deferred tax expense excluding items below	$ 205,262	$ 184,544	$ 210,856
Tax (expense) benefit allocated to other comprehensive income and other	173	(656)	(1,046)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	1,401	(16,417)	(41,366)
Deferred tax expense	$ 206,836	$ 167,471	$ 168,444

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

(Thousands of Dollars)	2015	2014
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 3,022,657	$ 2,628,577
Regulatory assets	156,499	134,550
Employee benefits	16,632	7,066
Other	20,202	32,663
Total deferred tax liabilities	$ 3,215,990	$ 2,802,856
Deferred tax assets:		
NOL carryforward	$ 402,784	$ 217,323
Tax credit carryforward	173,430	139,474
Rate refund	26,298	30,785
Regulatory liabilities	10,188	16,585
Deferred investment tax credits	11,419	12,200
Other	28,246	28,126
Total deferred tax assets	$ 652,365	$ 444,493
Net deferred tax liability	$ 2,563,625	$ 2,358,363

7. Benefit Plans and Other Postretirement Benefits

Consistent with the process for rate recovery of pension and postretirement benefits for its employees, NSP-Minnesota accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy Inc. as multiple employer plans. NSP-Minnesota is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, NSP-Minnesota accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for NSP-Minnesota employees.

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. Approximately 62 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2015, NSP-Minnesota had 1,983 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 265 nuclear operation bargaining employees covered under several collective-bargaining agreements. Some of these agreements expired in 2015, but were extended to 2016. The remaining agreements expire in 2016 and 2018.

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, which includes NSP-Minnesota, 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 Inc.'s and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2015 and 2014 were $41.8 million and $46.5 million, respectively, of which $5.1 million and $5.7 million was attributable to NSP-Minnesota. In 2015 and 2014, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $9.5 million and $4.7 million, respectively, of which $0.6 million and $0.5 million was attributable to NSP-Minnesota. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

Xcel Energy Inc. and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the historical returns achieved by the 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 Inc. and NSP-Minnesota continually review pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long term.

- Investment returns in 2015, 2014 and 2013 were below the assumed level of 7.25 percent in for all years; and
- In 2016, NSP-Minnesota's expected investment-return assumption is 7.10 percent.

The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for NSP-Minnesota at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	41%	39%
Long-duration fixed income and interest rate swap securities	23	23
Short-to-intermediate fixed income securities	14	14
Alternative investments	20	22
Cash	2	2
Total	100%	100%

The 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, NSP-Minnesota's pension plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

	Dec. 31, 2015			
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash equivalents	$ 40,273	$ —	$ —	$ 40,273
Derivatives	—	596	—	596
Government securities	—	87,510	—	87,510
Corporate bonds	—	70,114	—	70,114
Asset-backed securities	—	680	—	680
Common stock	28,257	—	—	28,257
Private equity investments	—	—	40,023	40,023
Commingled funds	—	515,215	—	515,215
Real estate	—	—	16,182	16,182
Other	—	1,393	—	1,393
Total	$ 68,530	$ 675,508	$ 56,205	$ 800,243

	Dec. 31, 2014			
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash equivalents	$ 52,506	$ —	$ —	$ 52,506
Derivatives	—	185	—	185
Government securities	—	106,763	—	106,763
Corporate bonds	—	87,821	—	87,821
Asset-backed securities	—	1,073	—	1,073
Mortgage-backed securities	—	3,152	—	3,152
Common stock	29,368	—	—	29,368
Private equity investments	—	—	46,982	46,982
Commingled funds	—	543,008	—	543,008
Real estate	—	—	16,660	16,660
Securities lending collateral obligation and other	—	(6,603)	—	(6,603)
Total	$ 81,874	$ 735,399	$ 63,642	$ 880,915

The following tables present the changes in NSP-Minnesota's Level 3 pension plan assets for the years ended Dec. 31, 2015, 2014 and 2013:

(Thousands of Dollars)	Jan. 1, 2015	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3	Dec. 31, 2015
Private equity investments	$ 46,982	$ 8,896	$ (11,827)	$ (4,028)	$ —	$ 40,023
Real estate	16,660	2,243	(3,556)	835	—	16,182
Total	$ 63,642	$ 11,139	$ (15,383)	$ (3,193)	$ —	$ 56,205

(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	$ 48,633	$ 7,949	$ (6,785)	$ (2,815)	$ —	$ 46,982
Real estate	14,904	1,104	(1,197)	1,849	—	16,660
Total	$ 63,537	$ 9,053	$ (7,982)	$ (966)	$ —	$ 63,642

(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	$ 4,741	$ —	$ —	$ —	$ (4,741)	$ —
Mortgage-backed securities	13,472	—	—	—	(13,472)	—
Private equity investments	54,091	7,018	(11,403)	(1,073)	—	48,633
Real estate	21,978	(833)	1,860	2,920	(11,021)	14,904
Total	$ 94,282	$ 6,185	$ (9,543)	$ 1,847	$ (29,234)	$ 63,537

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2015	2014
Accumulated Benefit Obligation at Dec. 31	$ 954,610	$ 1,027,467
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 1,099,671	$ 1,062,633
Service cost	31,556	29,699
Interest cost	43,214	47,309
Actuarial (gain) loss	(60,091)	74,204
Benefit payments	(91,227)	(114,174)
Obligation at Dec. 31	$ 1,023,123	$ 1,099,671

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 880,915	$ 887,642
Actual (loss) return on plan assets	(22,180)	55,332
Employer contributions	32,735	52,115
Benefit payments	(91,227)	(114,174)
Fair value of plan assets at Dec. 31	$ 800,243	$ 880,915

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status [(a)]	$ (222,880)	$ (218,756)

(a) Amounts are recognized in noncurrent liabilities on NSP-Minnesota's consolidated balance sheet.

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 589,796	$ 611,069
Prior service cost	4,710	5,646
Total	$ 594,506	$ 616,715

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	$ 42,898	$ 45,896
Noncurrent regulatory assets	551,608	570,819
Total	$ 594,506	$ 616,715
Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.66%	4.11%
Expected average long-term increase in compensation level	4.00%	3.75%
Mortality table	RP 2014	RP 2014

Mortality **—** In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. NSP-Minnesota has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on its population and specific experience. During 2015, a new projection table was released (MP 2015). NSP-Minnesota evaluated the updated projection table and concluded that the methodology adopted at Dec. 31, 2014 is consistent with the recently updated table and continues to be representative of its population.

Cash Flows **—** Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2012 through 2016 to meet minimum funding requirements.

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

- $125.0 million in January 2016, of which $49.4 million was attributable to NSP-Minnesota;
- $90.1 million in 2015, of which $32.7 million was attributable to NSP-Minnesota;
- $130.6 million in 2014, of which $52.1 million was attributable to NSP-Minnesota; and
- $192.4 million in 2013, of which $72.4 million was attributable to NSP-Minnesota.

For future years, Xcel Energy and NSP-Minnesota anticipate contributions will be made as necessary.

Plan Amendments **—** In 2015 and 2014 there were no plan amendments made which affected the projected benefit obligation. Xcel Energy, which includes NSP-Minnesota, amended the plan in 2013 resulting in a decrease of the projected benefit obligation due to fully insuring the long-term disability benefit for NSP bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

Benefit Costs — The components of NSP-Minnesota's net periodic pension cost were:

(Thousands of Dollars)	2015	2014	2013
Service cost	$ 31,556	$ 29,699	$ 33,167
Interest cost	43,214	47,309	43,734
Expected return on plan assets	(62,830)	(62,920)	(63,152)
Amortization of prior service cost	936	936	2,057
Amortization of net loss	46,192	44,785	52,988
Net periodic pension cost	59,068	59,809	68,794
Costs not recognized due to effects of regulation	(30,766)	(29,485)	(35,455)
Net benefit cost recognized for financial reporting	$ 28,302	$ 30,324	$ 33,339

	2015	2014	2013
Significant Assumptions Used to Measure Costs:			
Discount rate	4.11%	4.75%	4.00%
Expected average long-term increase in compensation level	3.75	3.75	3.75
Expected average long-term rate of return on assets	7.25	7.25	7.25

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs. Amounts allocated to NSP-Minnesota were $11.0 million, $10.3 million and $12.9 million in 2015, 2014 and 2013, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2016 pension cost calculations is 7.10 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets 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 actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for NSP-Minnesota was approximately $11.2 million in 2015, $11.1 million in 2014 and $10.4 million in 2013.

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees. NSP-Minnesota discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

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. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy Inc. and NSP-Minnesota at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	25%	25%
Short-to-intermediate fixed income securities	57	57
Alternative investments	13	13
Cash	5	5
Total	100%	100%

Xcel Energy Inc. and NSP-Minnesota base investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota'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 is not considered to be a material factor in postretirement health care costs.

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's proportionate allocation of the total postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

	Dec. 31, 2015			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 130	$ —	$ —	$ 130
Government securities	—	260	—	260
Insurance contracts	—	313	—	313
Corporate bonds	—	483	—	483
Asset-backed securities	—	190	—	190
Mortgage-backed securities	—	236	—	236
Commingled funds	—	1,358	—	1,358
Other	—	(1)	—	(1)
Total	$ 130	$ 2,839	$ —	$ 2,969

	Dec. 31, 2014			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 115	$ —	$ —	$ 115
Derivatives	—	1	—	1
Government securities	—	213	—	213
Insurance contracts	—	221	—	221
Corporate bonds	—	237	—	237
Asset-backed securities	—	16	—	16
Mortgage-backed securities	—	49	—	49
Commingled funds	—	1,237	—	1,237
Other	—	(8)	—	(8)
Total	$ 115	$ 1,966	$ —	$ 2,081

For the years ended Dec. 31, 2015 and 2014 there were no assets transferred in or out of Level 3. The following table presents the changes in NSP-Minnesota's Level 3 postretirement benefit plan assets for the years ended Dec. 31, 2013:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 [(a)]	Dec. 31, 2013
Asset-backed securities	$ 9	$ —	$ —	$ —	$ (9)	$ —
Mortgage-backed securities	483	—	—	—	(483)	—
Total	$ 492	$ —	$ —	$ —	$ (492)	$ —

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2015	2014
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 97,946	$ 108,232
Service cost	159	187
Interest cost	3,814	4,993
Medicare subsidy reimbursements	59	12
Plan participants' contributions	552	995
Actuarial gain	(5,197)	(5,742)
Benefit payments	(8,649)	(10,731)
Obligation at Dec. 31	$ 88,684	$ 97,946

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 2,081	$ 4,299
Actual return on plan assets	8	3
Plan participants' contributions	552	995
Employer contributions	8,977	7,515
Benefit payments	(8,649)	(10,731)
Fair value of plan assets at Dec. 31	$ 2,969	$ 2,081

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status	$ (85,715)	$ (95,865)
Current liabilities	(5,605)	(6,879)
Noncurrent liabilities	(80,110)	(88,986)
Net postretirement amounts recognized on consolidated balance sheets	$ (85,715)	$ (95,865)

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 40,864	$ 48,040
Prior service credit	(21,469)	(24,505)
Total	$ 19,395	$ 23,535

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Noncurrent regulatory assets	$ 18,133	$ 22,004
Deferred income taxes	515	625
Net-of-tax accumulated OCI	747	906
Total	$ 19,395	$ 23,535
Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.65%	4.08%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial	6.00%	6.50%

Effective Jan. 1, 2016, the initial medical trend rate was decreased from 6.5 percent to 6.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy Inc. and NSP-Minnesota base the 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 the retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on NSP-Minnesota:

	One Percentage Point	
(Thousands of Dollars)	**Increase**	**Decrease**
APBO	$ 8,558	$ (7,282)
Service and interest components	451	(376)

Cash Flows **—** The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes NSP-Minnesota, contributed $18.3 million, $17.1 million and $17.6 million during 2015, 2014 and 2013, respectively, of which $9.0 million, $7.5 million and $7.0 million were attributable to NSP-Minnesota. Xcel Energy expects to contribute approximately $12.3 million during 2016, of which $8.6 million is attributable to NSP-Minnesota.

Plan Amendments **—** In 2015 and 2014, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of NSP-Minnesota's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2015	2014	2013
Service cost	$ 159	$ 187	$ 120
Interest cost	3,814	4,993	4,901
Expected return on plan assets	(121)	(301)	(417)
Amortization of transition obligation	—	—	33
Amortization of prior service credit	(3,036)	(3,036)	(3,036)
Amortization of net loss	2,092	3,416	5,272
Net periodic postretirement benefit cost	$ 2,908	$ 5,259	$ 6,873

	2015	2014	2013
Significant Assumptions Used to Measure Costs:			
Discount rate	4.08%	4.82%	4.10%
Expected average long-term rate of return on assets	5.80	7.00	7.11

In addition to the benefit costs in the table above, for the postretirement health care plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs.

Projected Benefit Payments

The following table lists NSP-Minnesota's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2016	$ 87,981	$ 8,586	$ 12	$ 8,574
2017	89,225	8,118	11	8,107
2018	89,188	7,860	11	7,849
2019	90,255	7,522	11	7,511
2020	90,104	7,307	14	7,293
2021-2025	417,009	31,313	67	31,246

Multiemployer Plans

NSP-Minnesota contributes 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 sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2015, 2014 and 2013. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 850 in 2015 from approximately 1,000 in 2014. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota in multiemployer plans for the years presented:

(Thousands of Dollars)	2015	2014	2013
Multiemployer plan contributions:			
Pension	$ 17,223	$ 20,254	$ 23,515
Other postretirement benefits	135	273	390
Total	$ 17,358	$ 20,527	$ 23,905

8. Other Income (Expense), Net

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

(Thousands of Dollars)	2015	2014	2013
Interest income	$ 3,637	$ 4,778	$ 4,869
Other nonoperating income	166	651	174
Insurance policy expense	(3,357)	(4,849)	(5,696)
Other income (expense), net	$ 446	$ 580	$ (653)

9. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on NSP-Minnesota'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, generally referred to as FTRs, purchased from MISO, PJM, Electric Reliability Council of Texas and NYISO. 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. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, 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 NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of NSP-Minnesota.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $328.8 million and $312.1 million at Dec. 31, 2015 and 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $100.2 million and $74.1 million at Dec. 31, 2015 and 2014, respectively.

The following tables present the cost and fair value of NSP-Minnesota's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2015 and 2014:

	Dec. 31, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$ 27,484	$ 27,484	$ —	$ —	$ 27,484
Commingled funds	392,838	—	410,634	—	410,634
International equity funds	259,114	—	231,122	—	231,122
Private equity investments	105,965	—	—	157,528	157,528
Real estate	61,816	—	—	84,750	84,750
Debt securities:					
Government securities	24,444	—	21,356	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	65,276
International corporate bonds	13,726	—	12,801	—	12,801
Municipal bonds	49,255	—	51,589	—	51,589
Asset-backed securities	2,837	—	2,830	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	11,621
Equity securities:					
Common stock	473,615	647,159	—	—	647,159
Total	$ 1,495,599	$ 674,643	$ 807,229	$ 242,278	$ 1,724,150

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $34.1 million of miscellaneous investments.

(Thousands of Dollars)	Cost	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Fair Value Total
	Dec. 31, 2014				
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 $31.4 million of miscellaneous investments.

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

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3	Dec. 31, 2015
Private equity investments	$ 101,237	$ 32,029	$ —	$ 24,262	$ —	$ 157,528
Real estate	64,249	27,568	(9,611)	2,544	—	84,750
Total	$ 165,486	$ 59,597	$ (9,611)	$ 26,806	$ —	$ 242,278

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	$ 62,696	$ 22,078	$ (286)	$ 16,749	$ —	$ 101,237
Real estate	57,368	8,088	(9,794)	8,587	—	64,249
Total	$ 120,064	$ 30,166	$ (10,080)	$ 25,336	$ —	$ 165,486

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	Transfers Out of Level 3 [(b)]	Dec. 31, 2013
Private equity investments	$ 33,250	$ 24,201	$ —	$ 5,245	$ —	$ 62,696
Real estate	39,074	31,626	(18,622)	5,290	—	57,368
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$ 104,600	$ 55,827	$ (18,622)	$ 10,535	$ (32,276)	$ 120,064

(a) Gains and losses are deferred as a component of the regulatory asset for nuclear decommissioning.

(b) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2015:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$ —	$ —	$ —	$ 21,356	$ 21,356
U.S. corporate bonds	—	16,005	51,384	(2,113)	65,276
International corporate bonds	—	2,787	9,382	632	12,801
Municipal bonds	153	264	17,814	33,358	51,589
Asset-backed securities	—	—	2,830	—	2,830
Mortgage-backed securities	—	—	—	11,621	11,621
Debt securities	$ 153	$ 19,056	$ 81,410	$ 64,854	$ 165,473

Derivative Instruments Fair Value Measurements

NSP-Minnesota 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 — NSP-Minnesota enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2015, accumulated other comprehensive losses related to interest rate derivatives included $0.8 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 — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. NSP-Minnesota'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 — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

At Dec. 31, 2015, NSP-Minnesota had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. NSP-Minnesota 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. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2015 and 2014.

At Dec. 31, 2015, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, NSP-Minnesota 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 revenue, net of amounts credited to customers under margin-sharing mechanisms.

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

(Amounts in Thousands) [(a)(b)]	2015	2014
MWh of electricity	43,611	49,431
MMBtu of natural gas	7,971	173
Gallons of vehicle fuel	77	155

(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 — NSP-Minnesota 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 NSP-Minnesota'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.

NSP-Minnesota 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.

NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2015, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising $23.1 million or 35 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Three of the 10 most significant counterparties, comprising $8.0 million or 12 percent of this credit exposure at Dec. 31, 2015, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising $6.3 million or 10 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. 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 NSP-Minnesota's accumulated other comprehensive loss, included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2015	2014	2013
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (19,909)	$ (20,609)	$ (21,393)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(39)	(89)	5
After-tax net realized losses on derivative transactions reclassified into earnings	858	789	779
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (19,090)	$ (19,909)	$ (20,609)

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2015, 2014 and 2013 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1,385 [a]	$ —	$ —
Vehicle fuel and other commodity	(66)	—	73 [b]	—	—
Total	$ (66)	$ —	$ 1,458	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ (7,650) [c]
Electric commodity	—	(15,483)	—	14,735 [d]	—
Natural gas commodity	—	(4,878)	—	4,762 [e]	(3,585) [e]
Total	$ —	$ (20,361)	$ —	$ 19,497	$ (11,235)

	Year Ended Dec. 31, 2014				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1,387 [a]	$ —	$ —
Vehicle fuel and other commodity	(150)	—	(30) [b]	—	—
Total	$ (150)	$ —	$ 1,357	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 751 [c]
Electric commodity	—	(4,385)	—	(17,200) [d]	—
Natural gas commodity	—	4,576	—	(8,584) [e]	(2,627) [e]
Other commodity	—	—	—	—	643 [c]
Total	$ —	$ 191	$ —	$ (25,784)	$ (1,233)

(Thousands of Dollars)	Year Ended Dec. 31, 2013 — Pre-Tax Fair Value Gains Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: 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	$ —	$ —	$ 1,388 [a]	$ —	$ —
Vehicle fuel and other commodity	15	—	(49) [b]	—	—
Total	$ 15	$ —	$ 1,339	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 11,220 [c]
Electric commodity	—	65,884	—	(52,796) [d]	—
Natural gas commodity	—	1,039	—	368 [e]	(393) [d]
Total	$ —	$ 66,923	$ —	$ (52,428)	$ 10,827

(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 are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2015, 2014 and 2013. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, 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 NSP-Minnesota is unable to maintain its credit ratings. At Dec. 31, 2015 and 2014, no derivative instruments in a liability position would have required the posting of collateral or settlement of outstanding contracts if the credit ratings of NSP-Minnesota were downgraded below investment grade.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2015 and 2014.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2015:

	Dec. 31, 2015					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 88	$ 10,269	$ 1,250	$ 11,607	$ (5,542)	$ 6,065
Electric commodity	—	—	12,441	12,441	(167)	12,274
Natural gas commodity	—	128	—	128	(6)	122
Total current derivative assets	$ 88	$ 10,397	$ 13,691	$ 24,176	$ (5,715)	18,461
PPAs [(a)]						480
Current derivative instruments						$ 18,941
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 27,399	$ —	$ 27,399	$ (6,555)	$ 20,844
Total noncurrent derivative assets	$ —	$ 27,399	$ —	$ 27,399	$ (6,555)	20,844
PPAs [(a)]						1,490
Noncurrent derivative instruments						$ 22,334
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 113	$ —	$ 113	$ —	$ 113
Other derivative instruments:						
Commodity trading	118	7,541	554	8,213	(6,580)	1,633
Electric commodity	—	—	167	167	(167)	—
Natural gas commodity	—	1,362	—	1,362	(6)	1,356
Total current derivative liabilities	$ 118	$ 9,016	$ 721	$ 9,855	$ (6,753)	3,102
PPAs [(a)]						14,109
Current derivative instruments						$ 17,211
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ —	$ 19,865	$ —	$ 19,865	$ (9,780)	$ 10,085
Total noncurrent derivative liabilities	$ —	$ 19,865	$ —	$ 19,865	$ (9,780)	10,085
PPAs [(a)]						118,128
Noncurrent derivative instruments						$ 128,213

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota 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, NSP-Minnesota 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) NSP-Minnesota nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $4.3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2014:

	Dec. 31, 2014					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 14,326	$ 4,732	$ 19,058	$ (3,240)	$ 15,818
Electric commodity	—	—	37,051	37,051	(1,512)	35,539
Natural gas commodity	—	295	—	295	(4)	291
Total current derivative assets	$ —	$ 14,621	$ 41,783	$ 56,404	$ (4,756)	51,648
PPAs [(a)]						8,516
Current derivative instruments						$ 60,164
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)]						1,968
Noncurrent derivative instruments						$ 15,434
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 65	$ —	$ 65	$ —	$ 65
Other derivative instruments:						
Commodity trading	—	7,974	—	7,974	(7,974)	—
Electric commodity	—	—	1,512	1,512	(1,512)	—
Total current derivative liabilities	$ —	$ 8,039	$ 1,512	$ 9,551	$ (9,486)	65
PPAs [(a)]						12,229
Current derivative instruments						$ 12,294
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ —	$ 56	$ —	$ 56	$ —	$ 56
Other derivative instruments:						
Commodity trading	—	6,890	—	6,890	(6,033)	857
Total noncurrent derivative liabilities	$ —	$ 6,946	$ —	$ 6,946	$ (6,033)	913
PPAs [(a)]						134,123
Noncurrent derivative instruments						$ 135,036

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota 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, NSP-Minnesota 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) NSP-Minnesota nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2015, 2014 and 2013:

	Year Ended Dec. 31		
(Thousands of Dollars)	2015	2014	2013
Balance at Jan. 1	$ 40,271	$ 31,727	$ 16,649
Purchases	40,288	84,762	51,541
Settlements	(38,050)	(101,690)	(45,199)
Transfers out of Level 3	—	(1,093)	—
Net transactions recorded during the period:			
Gains recognized in earnings [a]	1,533	10,692	3,947
(Losses) gains recognized as regulatory assets and liabilities	(31,072)	15,873	4,789
Balance at Dec. 31	$ 12,970	$ 40,271	$ 31,727

(a) These amounts relate to commodity derivatives held at the end of the period.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2015 and 2013. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

As of Dec. 31, 2015 and 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

	2015		2014	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 4,534,122	$ 4,917,080	$ 4,188,682	$ 4,803,735

The fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2015 and 2014, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

10. Rate Matters

Pending and Recently Concluded Regulatory Proceedings — MPUC

Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case was based on a ROE of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million, or 6.9 percent, in 2014 and an additional $98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan. In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund. In 2014, NSP-Minnesota revised its requested rate increase to $115.3 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $221.3 million.

In May 2015, the MPUC ordered a total increase of $166.1 million, or 5.9 percent, consisting of $58.9 million and $125.2 million in 2014 and 2015, respectively, and an $18.0 million adjustment related to disallowance of certain Monticello LCM/EPU costs. The MPUC also approved a three-year, decoupling pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of changes in electric sales due to conservation and weather variability for these classes.

In July 2015, the MPUC deliberated on requests for reconsideration and determined the Monticello EPU project was not yet used-and-useful, as final approval related to the full EPU uprate condition had not been received from the NRC as of June 30, 2015. As a result, $13.8 million was excluded from final rates. Monticello subsequently received final NRC compliance approval in July 2015. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decisions resulted in a total estimated 2014 and 2015 annual rate increase of $149.4 million, or 5.3 percent.

The following table outlines the impact of the MPUC's July decision:

(Millions of Dollars)	MPUC July Decision
2014 and 2015 step increase - based on MPUC May order	$ 166.1
Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net	0.2
Total 2014 and 2015 step increase	$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated revenue impact	$ 145.8

NSP-Minnesota – Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below.

Request (Millions of Dollars)	2016	2017	2018
Rate request	$ 194.6	$ 52.1	$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	$ 163.7	$ 44.9	N/A
Rate base	$ 7,800	$ 7,700	$ 7,700

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years.

In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016. The MPUC also required NSP-Minnesota to file supplemental direct testimony addressing costs associated with the LCM at the PI nuclear plant. NSP-Minnesota filed supplemental testimony in January 2016 demonstrating that the capital work at PI, including the LCM, is required during the rate case period, higher costs associated with the LCM are necessary to operate the plant through the end of its licensed life and recovery of these costs will result in reasonably priced energy for customers.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	2016	2017	2018	Total
2014 multi-year rate case items:				
Excess depreciation reserve	$ 26.0	$ 51.0	$ —	$ 77.0
DOE settlement	25.7	—	—	25.7
Monticello LCM/EPU	11.2	(1.6)	(1.5)	8.1
	62.9	49.4	(1.5)	110.8
Additional items:				
Capital investments	128.7	12.8	44.6	186.1
Property taxes	30.2	7.6	5.2	43.0
NOL carryforwards	(6.3)	(24.5)	(6.5)	(37.3)
Other costs	(20.9)	6.8	8.6	(5.5)
	131.7	2.7	51.9	186.3
Total rate request	$ 194.6	$ 52.1	$ 50.4	$ 297.1

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

- Intervenors' direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- ALJ report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW. The Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

In March 2015, the MPUC voted to allow for full recovery, including a return, on approximately $415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used-and-useful for 2014. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Minnesota – 2016 TCR Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of $19.2 million of 2016 transmission investment costs not included in electric base rates. This filing included an option to keep approximately $59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 within the TCR rider or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. In November 2015, NSP-Minnesota submitted an update to its TCR filing in which it confirmed that it was requesting the MPUC approve keeping the two CapX2020 projects in the TCR rider, increasing the revenue requirements to $78.3 million, until the conclusion of the 2016 Minnesota electric rate case.

Recently Concluded Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota Infrastructure Rider — In December 2015, the SDPUC approved recovery of $10.2 million through the infrastructure rider effective beginning Jan. 1, 2016. As part of the South Dakota 2015 electric rate case, the infrastructure rider was refreshed with new projects and was also expanded as a mechanism to allow for possible recovery of other investments related to generation, transmission, and distribution.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years and in 2015 extended the mechanisms to the 2016 program year. The estimated average annual electric and natural gas incentives are $30.6 million and $3.6 million, respectively, based on the approved savings goals.

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

- In July 2015, the MPUC approved NSP-Minnesota’s 2014 CIP electric and natural gas financial incentives totaling $40.1 million and $5.8 million, respectively.
- In addition, the MPUC approved NSP-Minnesota’s proposed 2015 to 2016 electric and natural gas CIP riders. NSP-Minnesota estimates 2016 recovery of $21.5 million of electric CIP expenses and $9.2 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated $86.9 million and $3.7 million through electric and gas base rates, respectively.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In October 2015, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately $15.5 million from Minnesota gas utility customers beginning April 1, 2016. This request includes $1.9 million in over-recovery from 2015 and $4.5 million of deferred sewer separation and integrity management costs which is the 2016 portion of a five year amortization.

An MPUC decision is expected in the second half of 2016.

Pending Regulatory Proceedings — FERC

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO TOs, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013.

Subsequently, the FERC adopted a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

The ROE complaint was set for full hearing procedures. The complainants and intervenors filed testimony recommending a ROE between 8.67 percent and 9.54 percent. The FERC staff recommended a ROE of 8.68 percent. The MISO TOs recommended a ROE not less than 10.8 percent. In December 2015, an ALJ initial decision was issued recommending a ROE of 10.32 percent. Briefs on exceptions challenging the ALJ recommendation were filed in January 2016. A FERC order is expected to be issued later in 2016.

Certain MISO TOs separately requested FERC approval of a 50 basis point ROE adder for RTO membership, which was approved effective Jan. 6, 2015, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. Certain intervenors sought rehearing of the FERC order granting the ROE adder and FERC action is pending.

In February 2015, certain intervenors filed a second complaint to reduce the MISO region ROE to 8.67 percent, prior to an adder. FERC set the second complaint for hearings, and established a refund effective date of Feb. 12, 2015. The complainants and intervenors filed direct testimony in September 2015, the MISO TOs filed answering testimony in October 2015 and FERC staff filed testimony in November 2015. In January 2016, all parties updated their ROE analyses. The complainants and intervenors recommended ROEs between 8.72 percent and 9.32 percent while FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.96 percent. Hearings were held before an ALJ in February 2016. An ALJ initial decision is expected in June 2016 with a FERC decision expected in late 2016 or 2017.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of Dec. 31, 2015. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between $8 million and $10 million annually for the NSP System.

11. Commitments and Contingencies

Commitments

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2016 and 2033. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for NSP-Minnesota under these contracts as of Dec. 31, 2015, are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2016	$ 273.4	$ 112.2	$ 35.0	$ 99.9
2017	141.9	112.3	2.5	84.7
2018	106.8	62.7	—	43.5
2019	—	124.1	—	38.1
2020	—	46.9	—	27.9
Thereafter	—	599.2	—	185.0
Total [(a)]	$ 522.1	$ 1,057.4	$ 37.5	$ 479.1

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. NSP-Minnesota'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 has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of $104.4 million, $107.9 million and $106.0 million in 2015, 2014 and 2013, respectively. At Dec. 31, 2015, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy [(a)]
2016	$ 89.7	$ 81.6
2017	83.5	87.3
2018	52.8	93.2
2019	53.8	98.7
2020	54.8	105.4
Thereafter	310.5	662.5
Total [(b)]	$ 645.1	$ 1,128.7

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

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — NSP-Minnesota leases a variety of equipment and facilities used in the normal course of business. These 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 were approximately $78.9 million, $81.0 million and $79.6 million for 2015, 2014 and 2013, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of $61.5 million, $61.0 million and $59.1 million in 2015, 2014 and 2013, respectively, recorded to electric fuel and purchased power expenses.

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases in accordance with the applicable accounting guidance. Future commitments under all operating leases are:

(Millions of Dollars)	Operating Leases	PPA [a] [b] Operating Leases	Total Operating Leases
2015	$ 7.7	$ 63.3	$ 71.0
2016	8.4	64.4	72.8
2017	8.2	65.4	73.6
2018	12.7	82.3	95.0
2019	7.8	95.0	102.8
Thereafter	65.2	938.2	1,003.4

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2039.

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 purchases power from independent power producing entities for which NSP-Minnesota is required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which NSP-Minnesota procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the associated independent power producing entity.

NSP-Minnesota has determined that certain independent power producing entities are variable interest entities. NSP-Minnesota 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.

NSP-Minnesota 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. NSP-Minnesota 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. NSP-Minnesota had approximately 1,069 MW of capacity under long-term PPAs as of Dec. 31, 2015 and 2014 with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2028.

Guarantees — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	$ 4.8	$ —	2019	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

Environmental Contingencies

NSP-Minnesota has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Minnesota believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Minnesota 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 NSP-Minnesota, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, NSP-Minnesota 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. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by NSP-Minnesota, its predecessors, or other entities; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to be a PRP that sent wastes to that site.

MGP Sites

Fargo, N.D. MGP Site — In May 2015, in connection with a city water main replacement and street improvement project in Fargo, N.D., underground pipes, tars and impacted soils, which may be related to a former MGP site operated by NSP-Minnesota or a prior company, were discovered. After initial reports and discussions with the City of Fargo and the North Dakota Department of Health, NSP-Minnesota removed the impacted soils and other materials from the project area. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. At this time, NSP-Minnesota's investigation of the site is preliminary as information is still being gathered. In October 2015, NSP-Minnesota initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota will likely establish a scheduling order for the case in the first quarter of 2016.

As of Dec. 31, 2015, NSP-Minnesota had recorded a liability of $2.7 million related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota's potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In July 2015, NSP-Minnesota filed a request with the NDPSC for approval to initially defer the portion of investigation and response costs allocable to the North Dakota jurisdiction. In December 2015, the NDPSC approved NSP-Minnesota's request.

Other MGP Sites — NSP-Minnesota is currently involved in investigating and/or remediating several other MGP sites where regulated materials may have been deposited. NSP-Minnesota has identified four sites 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. NSP-Minnesota anticipates that the majority of the remediation at these sites will continue through at least 2016. NSP-Minnesota had accrued $0.2 million and $0.1 million for all of these sites at Dec. 31, 2015 and Dec. 31, 2014, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. NSP-Minnesota anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

Asbestos Removal — Some of NSP-Minnesota's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. NSP-Minnesota has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) —In September 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. NSP-Minnesota has reviewed the final rule and is in the process of evaluating whether the costs of compliance could have a material impact on the results of operations, financial position or cash flows. NSP-Minnesota believes that compliance costs would be recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. NSP-Minnesota estimates the likely cost for complying with impingement requirements may be incurred between 2016 and 2027 and is approximately $45 million. NSP-Minnesota believes at least six 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 $190 million depending on the outcome of certain entrainment studies and cost-benefit analyses. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term "Waters of the U.S." will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. The rule went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

Air

GHG Emission Standard for Existing Sources (Clean Power Plan or CPP) — In October 2015, a final rule was published by the EPA for GHG emission standards for existing power plants. States must develop implementation plans by September 2016, with the possibility of an extension to September 2018, or the EPA will prepare a federal plan for the state. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA's state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The CPP is currently being challenged by multiple parties in the D.C. Circuit Court. In January 2016, the D.C. Circuit Court denied requests to stay the effectiveness of the rule as well as ordered expedited review of the CPP, with briefings to be completed and oral arguments held by June 2016. Following the D.C. Circuit Court's denial of motions for stay, multiple parties filed requests for stay with the U.S. Supreme Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. The stay will remain in effect until, first, the D.C. Circuit Court and then the U.S. Supreme Court have ruled on the challenges to the CPP.

NSP-Minnesota has undertaken a number of initiatives that reduce GHG emissions and respond to state renewable and energy efficiency goals. The CPP could require additional emission reductions in states in which NSP-Minnesota operates. If state plans do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. Until NSP-Minnesota has more information about SIPs or knows the requirements of the EPA's upcoming final rule on federal plans for the states that do not develop related plans, NSP-Minnesota cannot predict the costs of compliance with the final rule once it takes effect. NSP-Minnesota believes compliance costs will be recoverable through regulatory mechanisms. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the CPP or cost recovery is not provided in a timely manner, it could have a material impact on results of operations, financial position or cash flows.

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO_2 and NOx from utilities in the eastern half of the United States, including Minnesota, using an emissions trading program. CSAPR compliance in 2015 did not and 2016 is not expected to have a material impact on the results of operations, financial position or cash flows.

CSAPR was adopted to address interstate emissions impacting downwind states' attainment of the 1997 ozone NAAQS and the 1997 and 2006 particulate NAAQS. As the EPA revises the NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. If adopted as proposed, the ozone season emission budget for NOx is not expected to impact NSP-Minnesota.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the BART requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In its first regional haze SIP, Minnesota identified the NSP-Minnesota facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA supplemented its SIP in 2012, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 SIP. In June 2012, the EPA approved the SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2. The combustion controls were installed first and the scrubber upgrades were completed in December 2014, at a cost of $46.9 million. NSP-Minnesota has included these costs for recovery in rate proceedings.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In January 2016, the Eighth Circuit issued their opinion which upheld the EPA's approval of the SIP.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota (Minnesota District Court) by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club.

In May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO_2 emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

After a public comment period, the EPA notified the Minnesota District Court, in July 2015, that the settlement agreement is final. The EPA has seven months to recommend and adopt a rule which will set the agreed-upon SO_2 emissions. In October 2015, the EPA proposed a rule that would set the agreed-upon SO_2 emission limits. No public comments were received on this proposal. A final rule is anticipated in March 2016. NSP-Minnesota does not anticipate the costs of compliance with the proposed settlement will have a material impact on the results of operations, financial position or cash flows.

Implementation of the NAAQS for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where NSP-Minnesota operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree the EPA is requiring states to evaluate areas in three phases. If an area is designated nonattainment, the respective states will need to evaluate all SO_2 sources in the area. The state would then submit an implementation plan for the respective areas which would be due in 18 months, designed to achieve the NAAQS within five years. It is anticipated the areas near NSP-Minnesota's power plants would be evaluated in the next designation phase, ending December 2017. NSP-Minnesota cannot evaluate the impacts of this ruling until the designation of nonattainment areas is made and any required state plans are developed.

Revisions to the NAAQS for Ozone — In October 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where NSP-Minnesota operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota. In documents issued with the new standard, the EPA projects the Twin Cities Metropolitan Area will meet the new standard. Therefore, NSP-Minnesota does not expect a material impact on results of operations, financial position or cash flows.

NOV — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid-2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with electric production includes certain plants. NSP-Minnesota also recognized asbestos obligations for its general office building. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. NSP-Minnesota has 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.

NSP-Minnesota has recognized an ARO for the retirement costs of natural gas mains and lines and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings.

In April 2015, the EPA published the final rule regulating the management and disposal of coal combustion byproducts (e.g., coal ash) as a nonhazardous waste to the Federal Register. The rule became effective in October 2015. The estimated costs to comply with the final rule were incorporated into the cash flow revisions in 2015.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 12 for further discussion of nuclear obligations.

A reconciliation of NSP-Minnesota's AROs for the years ended Dec. 31, 2015 and 2014 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2015	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions [b]	Ending Balance Dec. 31, 2015
Electric plant						
Nuclear production decommissioning	$ 2,037,947	$ —	$ —	$ 103,077	$ —	$ 2,141,024
Steam production ash containment	63,730	—	—	1,878	(6,920)	58,688
Steam and other production asbestos	13,839	3,875	—	781	7,197	25,692
Wind production	36,165	31,085 [a]	—	1,760	644	69,654
Electric distribution	5,048	—	—	183	196	5,427
Other	1,903	127	(273)	75	84	1,916
Natural gas plant						
Gas transmission and distribution	26,362	—	—	1,035	—	27,397
Common and other property						
Common general plant asbestos	505	—	—	27	19	551
Common miscellaneous	675	—	—	24	44	743
Total liability	$ 2,186,174	$ 35,087	$ (273)	$ 108,840	$ 1,264	$ 2,331,092

(a) The liability recognized relates to the Pleasant Valley and Border Wind Farms which were placed in service during 2015.

(b) In 2015, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the asbestos and ash containment AROs were mainly related to updated cost estimates.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.7 billion as of Dec. 31, 2015, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Accretion	Cash Flow Revisions [a]	Ending Balance Dec. 31, 2014 [b]
Electric plant					
Nuclear production decommissioning	$ 1,628,298	$ —	$ 86,284	$ 323,365	$ 2,037,947
Steam production ash containment	48,947	—	1,393	13,390	63,730
Steam and other production asbestos	13,303	—	536	—	13,839
Wind production	34,511	—	1,654	—	36,165
Electric distribution	4,871	—	177	—	5,048
Other	1,390	456	54	3	1,903
Natural gas plant					
Gas transmission and distribution	333	2,281	22	23,726	26,362
Common and other property					
Common general plant asbestos	480	—	25	—	505
Common miscellaneous	630	—	23	22	675
Total liability	$ 1,732,763	$ 2,737	$ 90,168	$ 360,506	$ 2,186,174

(a) In 2014, revisions were made to various AROs due to revised estimated cash flows and the timing of those cash flows. Changes to estimated nuclear production decommissioning primarily relate to the triennial filing made to the MPUC in December 2014. See additional information in Note 12. Changes in estimated excavation costs and the timing of future retirement activities resulted in revisions to AROs related to gas transmission and distribution.

(b) There were no ARO liabilities settled during the year ended Dec. 31, 2014.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.7 billion as of Dec. 31, 2014, consisting of external investment funds.

Indeterminate AROs — Outside of the known and recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the amount of asbestos or cost of removal could be determined as of Dec. 31, 2015. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — NSP-Minnesota records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities 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, NSP-Minnesota has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2015 and 2014 were $430 million and $396 million, respectively.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.1 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $19.9 million for business interruption insurance and $43.7 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

NSP-Minnesota 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 NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Other Contingencies

See Note 10 for further discussion.

12. Nuclear Obligations

***Fuel Disposal* —** NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately $5 million in 2014 and $10 million in 2013. There were no DOE fuel disposal assessments in 2015. In total, NSP-Minnesota paid approximately $452.1 million to the DOE through Dec. 31, 2015.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 15 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks. Other alternatives for spent fuel storage are being investigated until a DOE facility is available.

***Regulatory Plant Decommissioning Recovery* —** Decommissioning activities related to NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota's 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of $14 million to be recovered in utility customer rates starting in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2015, NSP-Minnesota has accumulated $1.7 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

	Regulatory Basis	
(Thousands of Dollars)	2015	2014
Estimated decommissioning cost obligation from most recently approved study (in 2014 and 2011 dollars, respectively)	$ 3,012,342	$ 2,694,079
Effect of escalating costs (to 2015 and 2014 dollars, respectively, at 4.36/3.36 percent and 3.63/2.63 percent, respectively)	126,464	289,907
Estimated decommissioning cost obligation (in current dollars)	3,138,806	2,983,986
Effect of escalating costs to payment date (4.36/3.36 percent and 3.63/2.63 percent, respectively)	8,066,688	5,597,302
Estimated future decommissioning costs (undiscounted)	11,205,494	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 3.01 percent and 2.82 percent for 2015 and 2014, respectively)	(6,891,392)	(5,044,470)
Discounted decommissioning cost obligation	$ 4,314,102	$ 3,536,818
Assets held in external decommissioning trust	$ 1,724,150	$ 1,703,921
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,589,952	1,832,897

Calculations and data used by the regulator in approving company rates are useful in assessing future cash flows. The regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2015	2014
Discounted decommissioning cost obligation - regulated basis	$ 4,314,102	$ 3,536,818
Differences in discount rate and market risk premium	(1,275,438)	(1,275,101)
Operating and maintenance costs not included for GAAP	(897,640)	(547,135)
Differences in cost studies (2011 versus 2014, no change in 2015)	—	323,365
Nuclear production decommissioning ARO - GAAP	$ 2,141,024	$ 2,037,947

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Annual decommissioning recorded as depreciation expense: [(a)]	$ 6,862	$ 7,138	$ 6,402

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation.

13. Regulatory Assets and Liabilities

NSP-Minnesota's consolidated financial statements are prepared 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 the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota 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 of NSP-Minnesota at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations [a]	7	Various	$ 21,864	$ 356,716	$ 22,357	$ 353,845
Net AROs [b]	1, 11, 12	Plant lives	—	218,898	—	120,020
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	204,089	—	200,525
Contract valuation adjustments [c]	1, 9	Term of related contract	16,656	117,447	8,358	131,274
PI EPU	10	Nineteen years	2,967	65,060	8,743	62,141
Purchased power contracts costs	11	Term of related contract	268	41,268	—	40,312
Conservation programs [d]	1	One to two years	18,186	39,241	48,217	42,247
Nuclear refueling outage costs	1	One to two years	67,545	28,913	62,499	19,745
Renewable resources and environmental initiatives	11	One to two years	29,274	21,534	18,166	24,779
Gas pipeline inspection and remediation costs		Four years	3,247	13,662	4,564	18,258
Losses on reacquired debt	4	Term of related debt	1,933	13,435	1,928	15,368
Recoverable purchased natural gas and electric energy costs	1	One to five years	10,332	12,762	42,972	4,745
State commission adjustments	1	Plant lives	—	3,816	—	4,150
Other		Various	15,521	22,376	17,683	14,425
Total regulatory assets			$ 187,793	$1,159,217	$ 235,487	$1,051,834

(a) Includes $257.5 million and $282.4 million for the regulatory recognition of pension expense of which $21.3 million and $23.8 million is included in the current asset at Dec. 31, 2015 and 2014, respectively. Also included are $0.6 million and $2.9 million of regulatory assets related to the non-qualified pension plan of which $0.3 million is included in the current asset at Dec. 31, 2015 and 2014.

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

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

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

The components of regulatory liabilities shown on the consolidated balance sheets of NSP-Minnesota at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Plant removal costs	1, 11	Plant lives	$ —	$ 430,468	$ —	$ 396,091
Deferred income tax adjustment	1, 6	Various	—	27,181	—	28,262
Investment tax credit deferrals	1, 6	Various	—	19,289	—	20,614
DOE Settlement	11	One to two years	14,143	—	44,561	—
Contract valuation adjustments [a]	1, 9	Term of related contract	12,274	—	35,540	—
Deferred electric energy costs	1	Less than one year	9,112	—	10,521	—
Conservation programs [b]	1	Less than one year	—	—	68,690	—
Renewable resources and environmental initiatives	10, 11	Less than one year	—	—	7,119	—
Other		Various	8,391	14,949	5,177	6,816
Total regulatory liabilities [c]			$ 43,920	$ 491,887	$ 171,608	$ 451,783

(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.

(c) Revenue subject for refund of $62.1 million and $72.7 million for 2015 and 2014, respectively, is included in other current liabilities.

At Dec. 31, 2015 and 2014, approximately $89 million and $154 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes PI EPU costs and recoverable purchased natural gas and electric energy costs.

14. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2015 and 2014 were as follows:

	Year Ended Dec. 31, 2015			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (19,909)	$ 105	$ (1,010)	$ (20,814)
Other comprehensive loss before reclassifications	(39)	—	(1,061)	(1,100)
Losses (gains) reclassified from net accumulated other comprehensive loss	858	—	(25)	833
Net current period other comprehensive income (loss)	819	—	(1,086)	(267)
Accumulated other comprehensive (loss) income at Dec. 31	$ (19,090)	$ 105	$ (2,096)	$ (21,081)

	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 at Jan. 1	$ (20,609)	$ 73	$ (1,193)	$ (21,729)
Other comprehensive (loss) income before reclassifications	(89)	32	161	104
Losses reclassified from net accumulated other comprehensive loss	789	—	22	811
Net current period other comprehensive income	700	32	183	915
Accumulated other comprehensive (loss) income at Dec. 31	$ (19,909)	$ 105	$ (1,010)	$ (20,814)

Reclassifications from accumulated other comprehensive (loss) income for the years ended Dec. 31, 2015 and 2014 were as follows:

	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Thousands of Dollars)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$ 1,385 [(a)]	$ 1,387 [(a)]
Vehicle fuel derivatives	73 [(b)]	(30) [(b)]
Total, pre-tax	1,458	1,357
Tax benefit	(600)	(568)
Total, net of tax	858	789
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	156 [(c)]	232 [(c)]
Prior service cost	(196) [(c)]	(194) [(c)]
Total, pre-tax	(40)	38
Tax benefit	15	(16)
Total, net of tax	(25)	22
Total amounts reclassified, net of tax	$ 833	$ 811

(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 7 for details regarding these benefit plans.

15. Segments and Related Information

Operating results from the regulated electric utility and regulated natural gas utility are each separately and regularly reviewed by NSP-Minnesota's chief operating decision maker. NSP-Minnesota evaluates performance 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.

NSP-Minnesota has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- NSP-Minnesota's regulated electric utility segment generates electricity which is transmitted and distributed in Minnesota, North Dakota and South Dakota. 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 NSP-Minnesota's wholesale commodity and trading operations.
- NSP-Minnesota's regulated natural gas utility segment transports, stores and distributes natural gas in portions of Minnesota and North Dakota.
- 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 appliance repair services, nonutility real estate activities and revenues associated with processing solid waste into refuse-derived fuel.

Asset and capital expenditure information is not provided for NSP-Minnesota's reportable segments because as an integrated electric and natural gas utility, NSP-Minnesota operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2015					
Operating revenues [(a)]	$ 4,183,715	$ 545,135	$ 27,956	$ —	$ 4,756,806
Intersegment revenues	791	686	—	(1,477)	—
Total revenues	$ 4,184,506	$ 545,821	$ 27,956	$ (1,477)	$ 4,756,806
Depreciation and amortization	$ 434,462	$ 44,446	$ 434	$ —	$ 479,342
Interest charges and financing costs	183,632	12,191	215	—	196,038
Income tax expense	158,414	13,825	8,495	—	180,734
Net income	332,965	26,894	(3,020)	—	356,839

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2014					
Operating revenues [(a)]	$ 4,202,357	$ 757,695	$ 28,473	$ —	$ 4,988,525
Intersegment revenues	938	828	—	(1,766)	—
Total revenues	$ 4,203,295	$ 758,523	$ 28,473	$ (1,766)	$ 4,988,525
Depreciation and amortization	$ 368,213	$ 41,946	$ 681	$ —	$ 410,840
Interest charges and financing cost	177,183	11,595	178	—	188,956
Income tax expense (benefit)	185,570	19,524	(7,004)	—	198,090
Net income	355,937	35,518	13,460	—	404,915

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2013					
Operating revenues [a]	$ 4,062,440	$ 591,017	$ 26,153	$ —	$ 4,679,610
Intersegment revenues	680	640	—	(1,320)	—
Total revenues	$ 4,063,120	$ 591,657	$ 26,153	$ (1,320)	$ 4,679,610
Depreciation and amortization	$ 373,747	$ 40,163	$ 678	$ —	$ 414,588
Interest charges and financing cost	162,084	11,572	154	—	173,810
Income tax expense	183,854	17,416	(19,413)	—	181,857
Net income	338,900	29,891	24,555	—	393,346

(a) Operating revenues include $473 million, $475 million and $459 million of intercompany revenue for the years ended Dec. 31, 2015, 2014 and 2013, respectively. See Note 16 for further discussion of related party transactions by operating segment.

16. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 4 for further discussion.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2015	2014	2013
Operating revenues:			
Electric	$ 473,099	$ 474,542	$ 458,633
Gas	45	96	97
Operating expenses:			
Purchased power	70,504	68,703	68,518
Transmission expense	92,751	76,399	68,398
Other operating expenses — paid to Xcel Energy Services Inc.	439,151	456,578	387,912
Interest expense	238	208	288
Interest income	94	28	22

Accounts receivable and payable with affiliates at Dec. 31 were:

	2015		2014	
(Thousands of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 18,268	$ —	$ 17,333	$ —
PSCo	—	4,419	6,706	—
SPS	—	1,066	—	1,983
Other subsidiaries of Xcel Energy Inc.	14,582	54,300	28	48,562
	$ 32,850	$ 59,785	$ 24,067	$ 50,545

17. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Thousands of Dollars)	March 31, 2015	June 30, 2015	Sept. 30, 2015	Dec. 31, 2015
Operating revenues	$ 1,292,482	$ 1,081,974	$ 1,248,840	$ 1,133,510
Operating income	50,851	154,488	310,690	190,317
Net income	6,924	74,181	175,549	100,185

	Quarter Ended			
(Thousands of Dollars)	March 31, 2014	June 30, 2014	Sept. 30, 2014	Dec. 31, 2014
Operating revenues	$ 1,424,326	$ 1,124,759	$ 1,190,213	$ 1,249,227
Operating income	203,692	155,296	252,745	155,860
Net income	108,364	75,266	134,469	86,816

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

NSP-Minnesota maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2015, based on an evaluation carried out under the supervision and with the participation of NSP-Minnesota's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that NSP-Minnesota's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in NSP-Minnesota'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, NSP-Minnesota's internal control over financial reporting. NSP-Minnesota maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. NSP-Minnesota has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2015 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, NSP-Minnesota conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, NSP-Minnesota did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Effective January 2016, NSP-Minnesota implemented the general ledger modules of a new enterprise resource planning ("ERP") system to improve certain financial and related transaction processes.   During 2016 and 2017, NSP-Minnesota will continue implementing additional modules and expects to begin conversion of existing work management system to this same ERP system.   In connection with this ongoing implementation, NSP-Minnesota is updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting procedures. NSP-Minnesota does not believe that this implementation will have an adverse effect on its internal control over financial reporting.

This annual report does not include an attestation report of NSP-Minnesota's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by NSP-Minnesota's independent registered public accounting firm pursuant to the rules of the SEC that permit NSP-Minnesota to provide only management's report in this annual report.

Item 9B — Other Information

None.

PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for NSP-Minnesota in accordance with conditions set forth in general instructions I (1) (a) and (b) of Form 10-K for wholly-owned subsidiaries.

Item 10 — Directors, Executive Officers and Corporate Governance

Item 11 — Executive Compensation

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

The information required by Item 14 of Form 10-K is set forth under the heading “Independent Registered Public Accounting Firm - Audit and Non-Audit Fees” in Xcel Energy Inc.'s definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 4, 2016. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1.	Consolidated Financial Statements:
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2015.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Balance Sheets — As of Dec. 31, 2015 and 2014.
	Consolidated Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2015, 2014 and 2013.
	Consolidated Statements of Capitalization — As of Dec. 31, 2015 and 2014.
2.	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2015, 2014 and 2013.
3.	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

3.01*	Articles of Incorporation and Amendments of Northern Power Corp. (renamed Northern States Power Co. (a Minnesota corporation) on Aug. 21, 2000) (Exhibit 3.01 to Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
3.02*	By-Laws of Northern States Power Co. (a Minnesota corporation) as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 000-31387)).
4.01*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year ended Dec. 31, 1988 (file no. 001-03034)). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
	Supplemental Trust Indenture dated April 1, 1997, creating $100 million principal amount of 8.5 percent First Mortgage Bonds, Series due Sept. 1, 2019 and $27.9 million principal amount of 8.5 percent First Mortgage Bonds, Series due March 1, 2019 (Exhibit 4.47 to Form 10-K (file no. 001-03034) dated Dec. 31, 1997).
	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
4.02*	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).
4.03*	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).
4.04*	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).
4.05*	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).
4.06*	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).
4.07*	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).
4.08*	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).

4.09*	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.
4.10*	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).
4.11*	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. 14, 2010 (file no. 001-31387)).
4.12*	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)).
4.13*	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))
4.14*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125 percent First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387)).
4.15*	Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300,000,000 principal amount of 2.20 percent First Mortgage Bonds, Series due Aug. 15, 2020 and $300,000,000 principal amount of 4.00 percent First Mortgage Bonds, Series due Aug. 15, 2045 (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Aug. 11, 2015 (file no. 001-31387)).
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan (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*	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)).
10.07*	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).
10.08*+	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).
10.09*+	Xcel Energy 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).
10.10*+	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 (file no. 001-03034) dated April 6, 2010).
10.11*+	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).
10.12*+	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 (file no. 001-03034) dated April 6, 2010).
10.13*+	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).
10.14*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (as amended and restated effective Feb. 17, 2010) (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.15*+	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).

10.16a*+	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).
10.16b*+	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).
10.17*+	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 Apr. 5, 2011).
10.18*+	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).
10.19*+	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).
10.20*+	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).
10.21*+	First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.22*+	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).
10.23*+	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).
10.24*+	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).
10.25*+	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).
10.26*	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 99.02 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).
10.27*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2015).
10.28*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. (As First Effective May 20, 2015) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.02 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.29*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.03 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.30*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement. (Exhibit 10.28 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
10.31*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.29 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
23.01	Consent of Independent Registered Public Accounting Firm.
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 NSP-Minnesota's Annual Report on Form 10-K for the year ended Dec. 31, 2015 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Stockholder's Equity, (vi) the Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, and (ix) Schedule II.

SCHEDULE II

NSP-MINNESOTA AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2015, 2014 AND 2013
(amounts in thousands)

		Additions			
	Balance at Jan. 1	Charged to Costs and Expenses	Charged to Other Accounts [(a)]	Deductions from Reserves [(b)]	Balance at Dec. 31
Allowance for bad debts:					
2015	$ 22,937	$ 14,420	$ 4,412	$ 21,019	$ 20,750
2014	20,216	17,193	5,469	19,941	22,937
2013	20,420	13,418	5,190	18,812	20,216

(a) Recovery of amounts previously written off.

(b) Deductions relate primarily to bad debt write-offs.

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.

	NORTHERN STATES POWER COMPANY (A MINNESOTA CORPORATION)
Feb. 22, 2016	/s/ TERESA S. MADDEN
	Teresa S. Madden
	Executive Vice President, Chief Financial Officer and Director
	(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	/s/ CHRISTOPHER B. CLARK
Ben Fowke	Christopher B. Clark
Chairman, Chief Executive Officer and Director	President and Director
(Principal Executive Officer)	
/s/ TERESA S. MADDEN	/s/ JEFFREY S. SAVAGE
Teresa S. Madden	Jeffrey S. Savage
Executive Vice President, Chief Financial Officer and Director	Senior Vice President, Controller
(Principal Financial Officer)	(Principal Accounting Officer)
/s/ MARVIN E. MCDANIEL, JR.	
Marvin E. McDaniel, Jr.	
Director	

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

NSP-Minnesota has not sent, and does not expect to send, an annual report or proxy statement to its security holder.