XCEL ENERGY INC
Form 10-K
February 21, 2014

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

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

For the fiscal year ended December 31, 2013
or

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

Commission File Number: 001-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

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

414 Nicollet Mall
Minneapolis, MN 55401
(Address of principal executive offices)
Registrant’s telephone number, including area code: 612-330-5500
Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ý Yes o No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes ý No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ý Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes o No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. ý Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes ý No
As of June 30, 2013, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $14,093,360,676 and there were 497,295,719 shares of common stock outstanding.
As of February 17, 2014, there were 498,288,164 shares of common stock outstanding, $2.50 par value.
DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2014 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS
Index

Table of Contents

PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

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

Federal and State Regulatory Agencies

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

3

Table of Contents

Electric, Purchased Gas and Resource Adjustment Clauses

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

Other Terms and Abbreviations

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

COLI	Corporate owned life insurance
CON	Certificate of need
CP	Coincident peak
CPCN	Certificate of public convenience and necessity
CSAPR	Cross-State Air Pollution Rule

Table of Contents

CWIP	Construction work in progress
EEI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share
ERCOT	Electric Reliability Council of Texas
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
FTY	Forecast test year
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
HTY	Historic test year
IFRS	International Financial Reporting Standards
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
MGP	Manufactured gas plant
MISO	Midcontinent Independent Transmission System Operator, Inc.
Moody’s	Moody’s Investor Services
MVP	Multi-value project
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOx	Nitrogen oxide
NOV	Notice of violation
NSPS	New source performance standard
NTC	Notifications to construct
NYISO	New York Independent System Operator
O&M	Operating and maintenance
OCC	Office of Consumer Counsel
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PSP	Performance share plan
PTC	Production tax credit
PV	Photovoltaic
QF	Qualifying facilities
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity
RPS	Renewable portfolio standards
RSG	Revenue sufficiency guarantee

RSU	Restricted stock unit
RTO	Regional Transmission Organization
ROFR	Right of first refusal
SCR	Selective catalytic reduction

Table of Contents

Sharyland	Sharyland Distribution and Transmission Services, LLC
SIP	State implementation plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor’s	Standard & Poor’s Ratings Services
TSR	Total shareholder return

Measurements

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

Table of Contents

COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2013, Xcel Energy Inc.'s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, and serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

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

Xcel Energy's corporate strategy focuses on four core objectives: driving operational excellence; providing options and solutions to customers; investing for the future; and enhancing engagement with employees, customers, shareholders, communities and policy makers. These core objectives are designed to provide an attractive total return to our investors, including long-term annual EPS growth of four to six percent and annual dividend increases of four to six percent. Xcel Energy files periodic rate cases and establishes formula rates or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations. Environmental leadership is a core priority for Xcel Energy and is designed to meet customer and policy maker expectations for clean energy at a competitive price while creating shareholder value.

NSP-Minnesota

NSP-Minnesota is a utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately four percent of its total KWh sold in 2013. 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 2013. 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.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation, which owns NMC, an inactive company.

Table of Contents

NSP-Wisconsin

NSP-Wisconsin is a utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in this service territory. NSP-Wisconsin provides electric utility service to approximately 253,000 customers and natural gas utility service to approximately 110,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2013. Although NSP-Wisconsin's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Wisconsin's large commercial and industrial electric sales include the following industries: food products, paper, allied products, oil and gas extraction and sand mining. For small commercial and industrial customers, significant electric retail sales include the following industries: grocery and dining establishments, educational services and food products. Generally, NSP-Wisconsin's earnings contribute approximately five percent to 10 percent of Xcel Energy's consolidated net income.

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

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reservoirs; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 13 percent of its total KWh sold in 2013. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.3 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2013. Although PSCo's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of PSCo's large commercial and industrial electric sales include the following industries: fabricated metal products, oil and gas extraction and communications. For small commercial and industrial customers, significant electric retail sales include the following industries: real estate and dining establishments. Generally, PSCo's earnings contribute approximately 45 percent to 55 percent of Xcel Energy's consolidated net income.

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

SPS

SPS is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 33 percent of its total KWh sold in 2013. SPS provides electric utility service to approximately 383,000 retail customers in Texas and New Mexico. Approximately 73 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2013. Although SPS' large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of SPS' large commercial and industrial electric sales include the following industries: oil and gas extraction, as well as petroleum and coal products. For small commercial and industrial customers, significant electric retail sales include the following industries: oil and gas extraction and crop related agricultural industries. Generally, SPS' earnings contribute approximately five percent to 15 percent of Xcel Energy's consolidated net income.

Other Subsidiaries

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

Table of Contents

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

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

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

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

ELECTRIC UTILITY OPERATIONS

NSP-Minnesota
Public Utility Regulation

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

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

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

- CIP — The CIP recovers the costs of programs that help customers save energy. The CIP includes a comprehensive list of programs that benefit all customers including Saver's Switch®, energy efficiency rebates and energy audits.
- EIR — The EIR recovers the costs of environmental improvement projects.
- RDF — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- RES — The RES recovers the cost of new renewable generation.
- SEP — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- TCR — The TCR recovers costs associated with new investments in electric transmission.
- Infrastructure — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes.

The MPUC approved NSP-Minnesota's request that the recovery of the costs associated with the EIR and RES be included in base rates in the Minnesota electric rate case in 2012. No costs are being recovered through the EIR at this time. NSP-Minnesota will continue to track PTCs associated with company-owned renewable projects and reflect the difference between the base rate amount and actual costs in the RES adjustment clause.

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.

Table of Contents

Minnesota state law requires NSP-Minnesota to invest two percent of its state electric revenues in CIP. NSP-Minnesota was in compliance with this standard in 2013 and expects to be in compliance in 2014. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

CIP Triennial Plan — In October 2012, the DOC approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the savings goals and budgets over the previous plan. The plan sets an electric goal of annually saving the equivalent of 1.5 percent of sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent of sales. The combined electric and gas budgets average $104.9 million per year over the 2013 through 2015 period.

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 2014, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2011	2012	2013	2014 Forecast
NSP System	9,792	9,475	9,524	9,212

The peak demand for the NSP System typically occurs in the summer. The 2013 uninterrupted system peak demand for the NSP System occurred on Aug. 26, 2013. The 2011 peak demand occurred on a day with extremely high temperatures and humidity, which resulted in the highest uninterrupted system peak demand since July 31, 2006. The 2012 peak demand occurred uninterrupted on a day with weather much closer to normal peak day conditions. The 2013 peak demand includes the effect of warmer weather partially offset by the impact of the termination of several firm wholesale contracts primarily at NSP-Wisconsin and also reflects the impact of two large commercial and industrial customers at NSP-Minnesota that have ceased operations. These two large customers represented 1.3 percent, 0.4 percent, and zero percent of NSP System sales in 2011, 2012, and 2013 respectively. The 2014 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

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

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

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's 2011-2025 Resource Plan and ordered a competitive acquisition process be conducted with the goal of adding approximately 500 MW of generation to the NSP System by 2019. Bid proposals were received in April 2013.

In September 2013, NSP-Minnesota recommended a self-build, 215 MW natural gas combustion turbine at the Black Dog site and a PPA with either Calpine's Mankato combined cycle natural gas project or Invenergy's Cannon Falls combustion turbine natural gas project. In October 2013, the DOC recommended the MPUC approve NSP-Minnesota's proposal.

On Dec. 31, 2013, the ALJ recommended the MPUC select a combination of a 100 MW solar proposal by Geronimo Energy, LLC and capacity credits offered by Great River Energy.

Table of Contents

In January 2014, NSP-Minnesota filed exceptions to the ALJ's report which supported NSP-Minnesota's original proposal, reiterated its commitment to meeting the solar mandate and made the following points:

- The ALJ's report focused on meeting a portion of the solar mandate even though the docket was designed to meet our resource need;
- Solar acquisition to meet the solar mandate should be conducted separately to encourage competition among solar developers;
- One or more gas fueled plants should be selected because they are large enough to meet the range of reasonably expected need, are least cost, and comply with environmental regulations; and
- Resource need uncertainty should be addressed through contract options to delay or cancel resources.

The MPUC is expected to make its selection determination in March 2014.

In the first half of 2013, NSP-Minnesota also issued a RFP for cost effective wind generation. In the summer of 2013, NSP-Minnesota filed a petition with the MPUC and the NDPSC seeking approval of four wind generation projects. The projects are as follows:

- A 200 MW ownership project for the Pleasant Valley wind farm in Minnesota, which is expected to be operational by October 2015;
- A 150 MW ownership project for the Border Winds wind farm in North Dakota, which is expected to be operational by 2015;
- A 200 MW PPA with Geronimo Energy, LLC for the Odell wind farm in Minnesota; and
- A 200 MW PPA with Geronimo Energy, LLC for the Courtenay wind farm in North Dakota.

In October 2013, the four wind projects were approved by the MPUC. A NDPSC decision is anticipated in early 2014. The feasibility of the Border Winds and Pleasant Valley projects are also dependent on the finalization of estimated transmission costs, which MISO is expected to determine in the first half of 2014.

CapX2020 — In 2009, the MPUC granted CONs to construct one 230 KV electric transmission line and three 345 KV electric transmission lines as part of the CapX2020 project. The estimated cost of the four major transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total investment.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 KV transmission line
In May 2012, the MPUC issued a route permit for the Minnesota portion of the project and the PSCW approved a CPCN for the Wisconsin portion of the project. Federal approval of the project was granted in January 2013. All avenues of appeal for the grant of project permits have now been exhausted. In July 2013, the FERC denied a complaint filed by two citizen groups in March 2013 against the project. Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2015.

Monticello, Minn. to Fargo, N.D. 345 KV transmission line
In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. The MPUC issued a route permit for the Minnesota portion of the St. Cloud, Minn. to Fargo, N.D. section in June 2011. Construction started on the Minnesota portion of the St. Cloud, Minn. to Fargo, N.D. segment in January 2012. The NDPSC granted a CPCN in January 2011 and a certificate of corridor compatibility and route permit for the portion of the line in North Dakota in September 2012. In January 2013, construction started on the project in North Dakota. The project is expected to go fully into service in 2015, although segments will be placed in service as they are completed.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line

The MPUC route permit approvals for the Minnesota segments were obtained in 2010 and 2011. In June 2011, the SDPUC approved a facility permit for the South Dakota segment. In December 2011, MISO granted the final approval of the project as a MVP. Construction started on the project in Minnesota in May 2012. The project is expected to go fully into service in 2015, although segments will be placed in service as they are completed.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line

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

Table of Contents

Minnesota Solar Initiatives — In May 2013, Minnesota's Governor signed into law legislation requiring that 1.5 percent of a public utility's total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized less than 20 kilowatts. The legislation also authorized NSP-Minnesota to offer two new solar programs: a community solar garden program that will provide bill credits to participating solar garden subscribers and a new solar energy incentive program for solar energy systems equal to or less than 20 kilowatts that authorizes the spending of $5.0 million over five years for production incentive payments. NSP-Minnesota is continuing to work toward bringing solar energy generation on line in support of these solar programs and legislative requirements. NSP-Minnesota submitted its proposal for a community solar garden program to the MPUC in September 2013. The MPUC may approve, disapprove or modify the program. NSP-Minnesota is currently developing the new solar energy incentive program. The legislation also provides for an alternative tariff based on a distributed solar value or Value of Solar methodology. As required by the legislation, the DOC developed and filed a distributed solar value methodology with the MPUC on Jan. 31, 2014. The MPUC must approve, modify with the consent of the DOC or disapprove the methodology within 60 days. Once the methodology is approved, NSP-Minnesota may elect to file a Value of Solar tariff. NSP-Minnesota provided comments to the DOC on the methodology of this Value of Solar alternative tariff on Oct. 1 and Oct. 8, 2013.

On Jan. 24, 2014, the MPUC approved $42 million in grants for renewable energy generation and research projects in Minnesota. Xcel Energy will fund the grants through its renewable development fund.

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. In August 2013, NSP-Minnesota filed comments opposing the DOC's proposal including a demonstration of the random and volatile results the DOC's fuel clause incentive proposal would have had if it were in place during the 2008-2012 period. Other utilities filed comments expressing similar concern with the DOC's incentive proposal, further indicating no support for modification to operation of the fuel clause. Subsequently, the DOC requested the MPUC convene a stakeholder meeting to discuss general purpose and function of the FCA program. In October 2013, the MPUC allowed the DOC an opportunity to discuss current challenges in evaluating the prudence of fuel clause costs and the DOC recommended that the MPUC consider using a three-year average of fuel costs established in base rates. The DOC continues to independently meet with a stakeholder group to explore alternative options to their proposal. The 2012 AAA docket is pending.

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.

Minneapolis, Minn. Franchise Agreement — The franchise agreement with the City of Minneapolis expires Dec. 31, 2014. In June 2013, the Minneapolis City Council authorized (i) public hearings to be held regarding the establishment of a municipal electric and natural gas utility and (ii) a $250,000 study that will explore the various paths the City of Minneapolis could take to achieve its energy goals, including examination of potential utility partnerships, changes to how the City of Minneapolis uses energy utility franchise fees and the potential for municipalization of one or both energy utilities. In August 2013, following public hearings, the Minneapolis City Council elected not to conduct a special election to pursue forming a municipal utility. Results of the exploratory study authorized by the Minneapolis City Council are due in the first quarter of 2014.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. 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 event at the nuclear generating plant in Fukushima, Japan in 2011 has resulted in additional regulation, which is expected to require additional capital expenditures and operating expenses. The NRC created an internal task force that developed recommendations on requirements for immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures and licensing processes. The task force released its recommendations in July 2011 in a written report which recommended actions to enhance U.S. nuclear generating plant readiness to safely manage severe events.

Table of Contents

In March 2012, the NRC issued three orders which included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance to meet the orders is expected to begin in the second quarter of 2015 with all units expected to be fully compliant by December 2016.

In June 2013, the NRC issued a revised order with regard to reliable hardened containment vents. The revised order added severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate and requires a second hardened vent off of the dry portion of the containment. The revised order requires that any necessary changes to the existing vent are to be completed by the second quarter of the 2017 refueling outage at the Monticello plant and a new vent to be added by the second quarter of the 2019 refueling outage. Portions of the work that fall under the requests for additional information are expected to be completed by 2018.

NSP-Minnesota expects that complying with these external event requirements will cost approximately $50 to $60 million at the Monticello and Prairie Island plants. The majority of these costs are expected to be capital in nature and are included in NSP-Minnesota’s capital expenditure forecasts. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

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

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 June 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application. In September 2011, the NRC announced that it was evenly divided on whether to take the affirmative action of overturning or upholding the ASLB decision. Because the NRC could not reach a decision, an order was issued instructing that information associated with the ASLB adjudication should be preserved. The ASLB complied and the proceeding has been suspended.

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. The utility industry, including Xcel Energy Inc. and NSP-Minnesota, are represented in these challenges by the NEI.

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

In November 2013, the U.S. Court of Appeals ordered the DOE to suspend the collection of the nuclear waste fund fee from nuclear utilities. The order required the DOE 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. The Nuclear Waste Policy Act provides that a proposal by the Secretary of Energy to adjust the fee shall be effective after a period of 90 days of continuous session unless either House of Congress adopts a resolution disapproving the Secretary's proposed adjustment.

Table of Contents

At the time that the DOE decided to stop the Yucca Mountain project and withdraw the application, the Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. In January 2012, the Blue Ribbon Commission report was issued. The report provided numerous policy recommendations that are being considered by the Secretary of Energy. In January 2013, the DOE provided its report to Congress relative to their plans to implement the Blue Ribbon Commission's recommendations including the required legislative changes and authorizations. The report also announced the Obama Administration's intent to make a pilot consolidated interim storage facility available in 2021, a larger consolidated interim storage facility available in 2025 and a deep geologic repository available in 2048. See Note 13 and Note 14 to the consolidated financial statements for further discussion.

Nuclear Spent Fuel Storage

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. As of Dec. 31, 2013, there were 35 casks loaded and stored at the Prairie Island plant and 15 canisters loaded and stored at the Monticello plant. An additional 29 casks for Prairie Island 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 Prairie Island Unit 1, and 2034 for Prairie Island Unit 2.

PFS — The eight partners of PFS, including NSP-Minnesota, have agreed to dissolve the LLC. PFS filed a letter with the NRC in December 2012 requesting to terminate the PFS license effective immediately. Subsequent to PFS requesting that the NRC terminate the PFS license, the NRC granted PFS a fee exemption for the 2013 license fees. Therefore, PFS has requested a 2014 fee exemption and is re-evaluating the future of the project. The efforts to dissolve the LLC are pending.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed it to prepare an EIS if there are significant impacts or an environmental assessment to support a finding of no significant impact. In September 2012, the NRC directed the NRC Staff to develop a Generic Environmental Impact Statement (GEIS) and revised WCD rule on the temporary storage of spent nuclear fuel, and to issue the final GEIS and WCD rule by September 2014.

NSP-Minnesota does not believe that there will be an immediate impact on operations at the Prairie Island or Monticello nuclear generating plants.

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

Nuclear Plant Power Uprates and Life Extension

Prairie Island Independent Spent Fuel Storage Installation (ISFSI) License Renewal — The current license to operate an ISFSI at Prairie Island was scheduled to expire in October 2013. An application to renew the ISFSI license for an additional 40 years until 2053 was submitted by NSP-Minnesota to the NRC in October 2011. As Prairie Island met the NRC's criteria for timely renewal by submitting its ISFSI license renewal application more than two years in advance of the expiration of the ISFSI's current license, it will be allowed to continue to operate under the current license until the NRC has rendered a decision on the license renewal application. In December 2012, the ASLB found that the Prairie Island Indian Community (PIIC) had standing to intervene and admitted three of the seven contentions put forward by the PIIC. The ASLB will establish a schedule for the hearing which should be completed by mid-2014.

Monticello Nuclear Uprate Project — NSP-Minnesota has filed with the MPUC two CONs related to changes at its Monticello nuclear generating plant. The first CON is related to state approval of a 20-year extension of the plant's operating license, which also needed approval by the NRC. The second CON is related to the expansion of output capacity at the plant by 71 MW, or 12 percent, referred to as an EPU. The MPUC approved the first life extension CON for resource planning purposes in 2008. In 2006, the NRC approved the 20-year extension of Monticello's operating license through 2030. The MPUC approved the second CON for EPU in 2008, and the NRC approved an EPU license amendment for the plant in December 2013.

NSP-Minnesota prepared for the upgrading and replacement of equipment at the plant to support an extended license period through a capital program known as LCM. Since the EPU project design also affected equipment needs and modifications at the plant, the LCM and EPU projects were integrated from an implementation standpoint to leverage project planning and efficiency.

Table of Contents

The plant life extension CON dealt mainly with the need for additional on-site storage of spent nuclear fuel, pending resolution of the longer-term federal issues with permanent fuel storage. The economic modeling for the life extension CON included underlying assumptions regarding future capital requirements, but the scope of the life extension CON proceeding did not specifically include discussion or request approval of capital investment for LCM work.

The EPU project CON dealt mainly with a resource planning proposal to expand output capacity at the plant and was planned to occur with the LCM project. The MPUC approval of the EPU CON authorized the resource need for additional capacity but did not include approval of a total project cost estimate. However, the modeling assumptions that combined EPU and LCM work were estimated to be $320 million in NSP-Minnesota's internal models. Estimated capital expenditures for the EPU portion of the integrated project were discussed in the EPU CON filing, and at the time such capital expenditures were estimated at approximately $133 million based on an allocation method.

In July 2013, NSP-Minnesota completed the Monticello 20-year life extension and EPU projects. Final costs for the integrated LCM/EPU project were approximately $665 million, excluding possible reductions from the results of ongoing vendor negotiations. Of that total cost amount, NSP-Minnesota estimated that approximately $146 million related to EPU capital work and $519 million related to LCM capital work. This cost level for the EPU work completed exceeded the CON estimate by approximately 10 percent. NSP-Minnesota believes that the LCM/EPU costs, while substantially higher than the preliminary estimates assumed at the time of the EPU CON, were reasonable and prudently incurred to allow for safe and reliable operations of the plant until 2030. NSP-Minnesota asserts that had it known of the higher costs at any earlier date, it would still have made economic sense to complete the project. NSP-Minnesota also believes that even at the higher cost level, the total capital investment made to prepare the Monticello plant for another 20 years of operation provides customers with a highly reliable, cost-effective carbon free generation source.

With the approval of the NRC EPU license amendment, the Monticello plant began testing ascension to higher power levels in December 2013. A second NRC license amendment (Maximum Extended Load Line Limit Analysis Plus, or MELLLA+) is also needed to proceed to full uprate capacity, for final approval of fuel configuration and utilization under full uprate conditions. NRC approval of this complementary MELLLA+ fuel license amendment, which includes a plant safety analysis allowing for greater operational flexibility, is anticipated to be received in the first half of 2014.

The method and timing of rate recovery of the costs associated with the Monticello life extension and EPU construction projects were included as part of the 2013 electric rate case and 2014 electric rate case filed in November 2013. The project costs will be subject to a prudence review by the MPUC coincident with the 2014 electric rate case, as discussed below.

In the 2013 Minnesota electric rate case final order, the MPUC initiated an investigation to determine whether the costs in excess of those included in the CON for NSP-Minnesota's Monticello LCM/EPU project were prudent. In October 2013, NSP-Minnesota filed a summary report and witness testimony to further support the change in and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors; (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendor's ability to attract and retain experienced workers; and (3) additional NRC licensing related requests over the five-plus year application process. The prudence investigation is currently scheduled to conclude in the fourth quarter of 2014.

In NSP-Wisconsin's recent rate case for 2014 rates, the PSCW ordered NSP-Wisconsin to defer cost recovery of $4.1 million, the portion of the interchange agreement amounts from NSP-Minnesota relating to the Monticello EPU project costs until the MPUC completes its prudence review.

Table of Contents

Energy Source Statistics

NSP System	Year Ended Dec. 31 2013 Millions of KWh	2013 Percent of Generation		2012 Millions of KWh	2012 Percent of Generation		2011 Millions of KWh	2011 Percent of Generation	
Coal	15,844	36	%	16,023	35	%	20,131	44	%
Nuclear	12,161	28		13,231	29		13,332	29	
Natural Gas	5,550	13		6,200	13		3,016	7	
Wind [(a)]	5,481	13		5,443	12		4,312	9	
Hydroelectric	3,223	7		3,193	7		3,444	8	
Other [(b)]	1,323	3		1,617	4		1,453	3	
Total	43,582	100	%	45,707	100	%	45,688	100	%
Owned generation	29,249	67	%	31,365	69	%	31,668	69	%
Purchased generation	14,333	33		14,342	31		14,020	31	
Total	43,582	100	%	45,707	100	%	45,688	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 0.008, 0.006, and 0.003 net million KWh for 2013, 2012, and 2011, respectively.

Fuel Supply and Costs

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

NSP System Generating Plants	Coal [(a)] Cost	Coal Percent		Nuclear Cost	Nuclear Percent		Natural Gas Cost	Natural Gas Percent		Weighted Average Owned Fuel Cost
2013	$2.20	49	%	$0.95	40	%	$5.08	11	%	$2.03
2012	2.13	47		0.90	42		4.21	11		1.88
2011	2.06	55		0.89	40		6.56	5		1.82

(a) Includes refuse-derived fuel and wood.

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, 2013 and 2012 were approximately 34 and 39 days usage, respectively. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2013 and 2012, coal requirements for the NSP System's major coal-fired generating plants were approximately 7.3 million tons and 7.2 million tons, respectively. The estimated coal requirements for 2014 are approximately 9.2 million tons. The coal requirements estimated for 2014 are higher primarily due to Sherco Unit 3 being placed back in service.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 94 percent of their estimated coal requirements in 2014, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years. 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 2014 and 2015. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Table of Contents

Nuclear — To operate NSP-Minnesota's nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium 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 67 percent of the requirements for 2019 through 2026.
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 57 percent of the requirements for 2022 through 2026.
- Current enrichment service contracts cover 100 percent of the requirements through 2024 and approximately 48 percent of the requirements for 2025 through 2026.

Fabrication services for Monticello and Prairie Island are 100 percent committed through 2027 and 2019, respectively.

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

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for power plants are procured under contracts with various terms 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 pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. These transportation rates are subject to revision based upon FERC approval of changes in the timing or amount of allowable cost recovery by providers. 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, 2013 and 2012, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately $389 million and $384 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2014 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, 2013, the NSP System was in compliance with mandated RPS, which require generation from renewable resources of 18 percent and 8.89 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively. Renewable energy comprised 22.9 percent and 22.4 percent of the NSP System's total owned and purchased energy for 2013 and 2012, respectively. Wind energy comprised 12.6 percent and 11.9 percent of the total owned and purchased energy on the NSP System for 2013 and 2012, respectively. Hydroelectric energy comprised 7.4 percent and 7.0 percent of the total owned and purchased energy on the NSP System for 2013 and 2012, respectively. Biomass and solar power comprised approximately 3.0 percent and 3.5 percent of the total owned and purchased energy on the NSP System for 2013 and 2012, respectively.

The NSP System also offers customer-focused renewable energy initiatives. Windsource®, one of the nation's largest voluntary renewable energy programs, allows customers in Minnesota, Wisconsin, and Michigan to purchase a portion or all of their electricity from renewable sources. In 2013, the number of customers increased to approximately 37,000 from 24,000 in 2012. Windsource MWh sales declined slightly due to the loss of a large commercial participant from approximately 184,000 MWh in 2012 to 181,000 MWh in 2013. 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 679 PV systems with approximately 7.3 MW of aggregate capacity and over 561 PV systems with approximately 6.3 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2013 and 2012, respectively.

Table of Contents

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Southwestern Minnesota. The NSP System currently has more than 100 of these agreements in place, with facilities ranging in size from under one MW to more than 200 MW. In October 2013, the MPUC approved four new projects, which are anticipated to provide up to 750 MW of capacity, including two projects totaling 350 MW that will be owned by NSP-Minnesota. Two of the projects, the Pleasant Valley wind farm in Minnesota and the Border Winds wind farm in North Dakota are expected to be operational by 2015. 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 these contracts was approximately $41 for 2013 and 2012. 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 2013 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2013.

The NSP System also owns and operates two wind farms. The 101 MW Grand Meadow Wind Farm and the 201 MW Nobles Wind Farm began generating electricity in 2008 and 2010, respectively. Collectively, the NSP System had approximately 1,870 MW of wind energy on its system at the end of 2013 and 2012. With the new projects, the NSP System is anticipated to have approximately 2,600 MW of wind power.

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 274 MW of capacity. For 2013, there were nine PPAs in place which provided approximately 37 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 850 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale Commodity Marketing Operations

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

NSP-Wisconsin
Public Utility Regulation

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

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

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

NSP-Wisconsin's wholesale electric rate schedules included a FCA to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy. However, as of Jan. 1, 2013, NSP-Wisconsin no longer served any wholesale municipal electric customers. Rates for wholesale municipal services provided in 2012 were subject to a final true-up, which was completed in 2013.

Table of Contents

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

2013 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for 2013 exceeded the levels authorized in Wisconsin retail rates, and were outside the two percent annual tolerance band established by the PSCW pursuant to the Wisconsin fuel cost recovery rules. Extended outages at two base load generation plants and higher than forecast prices in the MISO market were the primary causes of higher electric fuel costs. Rate recovery of the deferred amount is contingent on review and approval by the PSCW after opportunity for a hearing, and the earnings test based on NSP-Wisconsin's 2013 authorized ROE of 10.4 percent. NSP-Wisconsin has reviewed its 2013 fuel cost under-recovery, and has completed the earnings test, and has determined that it would be ineligible for rate recovery of any 2013 deferred fuel costs. Accordingly, NSP-Wisconsin has expensed all 2013 fuel costs.

Wisconsin Energy Efficiency Program — In Wisconsin, the primary energy efficiency program is funded by the state's utilities, but operated by independent contractors subject to oversight by the PSCW and the utilities. In 2013, NSP-Wisconsin was allocated approximately $8.3 million of the statewide program costs. NSP-Wisconsin recovers these costs in rates charged to Wisconsin retail customers.

Capacity and Demand

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

Energy Sources and Related Transmission Initiatives

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

NSP-Wisconsin CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the Hampton, Minn. to La Crosse, Wis. project in May 2012. The Wisconsin route is approximately 50 miles of new transmission line with an estimated cost of $211 million. Construction on the Wisconsin terminus of the line, the Briggs Road Substation, began in mid-2013 and construction on the Wisconsin portion of the line is anticipated to begin in mid-2014. The line is expected to go into service in 2015.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse, Wis. to Madison, Wis. Transmission Line — In October 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a CPCN for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. The proposed line, also known as the Badger Coulee line, would run between 159 and 182 miles, and cost between $514 and $552 million, depending upon the route ultimately approved by the PSCW. NSP-Wisconsin's share of the investment is estimated to be between $230 and $247 million. The cost estimates are based on a projected 2018 in-service year. In December 2011, MISO determined the line to be an MVP project, and as such, eligible for cost sharing under MISO's MVP tariff.

In November 2013, the PSCW found the application to be incomplete. A finding of incompleteness is a typical step for large transmission projects before the PSCW. In February 2014, NSP-Wisconsin and ATC submitted additional information in response to the PSCW's determination. The PSCW is expected to issue a decision on the CPCN application in the first half of 2015. If approved, NSP-Wisconsin and ATC anticipate beginning construction on the line in mid-2016, with completion by late-2018.

Fuel Supply and Costs

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

PSCo

Public Utility Regulation

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

Table of Contents

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

- ECA — The ECA recovers fuel and purchased power costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- PCCA — The PCCA recovers purchased capacity payments.
- SCA — The SCA recovers the difference between PSCo's actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised annually in January, as well as on an interim basis to coincide with changes in fuel costs.
- DSMCA — The DSMCA recovers DSM, interruptible service option credit costs and performance initiatives for achieving various energy savings goals.
- RESA — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of two percent of the customer's total bill.
- Wind Energy Service — Wind Energy Service is a premium service for those customers who voluntarily choose to pay an additional charge to increase the level of renewable resource generation used to meet the customer's load requirements.
- TCA — The TCA recovers transmission plant revenue requirements and allows for a return on CWIP outside of rate cases.

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

QSP Requirements — The CPUC established an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service. PSCo regularly monitors and records, as necessary, an estimated customer refund obligation under the QSP. PSCo files its proposed rate adjustment annually under the QSP. The CPUC conducts proceedings to review and approve these rate adjustments annually. In 2013, the CPUC extended the terms of the current QSP through the end of 2015.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2014, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2011	2012	2013	2014 Forecast
PSCo	6,896	6,689	6,678	6,459

The peak demand for PSCo's system typically occurs in the summer. The 2013 uninterrupted system peak demand for PSCo occurred on June 27, 2013. Comanche Unit 3 was off line, which increased PSCo's system load by approximately 260 MW for the backup power provided by PSCo to the joint owners. The forecasted 2014 system peak is lower than the 2013 peak, primarily due to the assumption that Comanche Unit 3 will be on line at the time of the peak and excludes the demand for the backup power supplied in 2013.

Energy Sources and Related Transmission Initiatives

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

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

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

Table of Contents

Colorado 2011 ERP and 2013 All-Source Solicitation — In March 2013, PSCo issued an All-Source RFP for 250 MW of generation by the end of 2018. PSCo also issued a separate wind RFP for PPAs only.

The CPUC provided final approval to PSCo's plan in December 2013, which includes the following:

- The addition of 450 MW of wind generation PPAs. This additional wind would bring the installed capacity on PSCo’s system in Colorado to 2,650 MW;
- The addition of 170 MW of utility-scale solar generation PPAs. PSCo currently has about 80 MW of utility-scale solar and approximately 188 MW of customer-sited solar generation;
- The addition of 317 MW of natural gas fired generation PPAs, which would come from existing power plants that previously supplied PSCo, but at reduced prices;
- Accelerated retirement of the 109 MW, coal-fired Unit 4 at the Arapahoe generating station, which occurred at the end of 2013;
- Confirmation of the retirement of the 45 MW, coal-fired Unit 3 at the Arapahoe generating station, which occurred at the end of 2013; and
- The continued operation of Cherokee generating station’s Unit 4 as a natural gas facility after 2017.

In addition, PSCo continues to execute on the remaining aspects of CACJA compliance including the construction of a new natural gas fired combined cycle unit at Cherokee generating station and the addition of emissions controls at the Pawnee and Hayden stations. PSCo also expects to retire the Cherokee Unit 3 and Valmont Unit 5 coal-fired power plants by the end of 2015 and 2017, respectively.

Boulder, Colo. Municipalization Exploration — PSCo’s franchise agreement with the City of Boulder expired on Dec. 31, 2010. In November 2010, the citizens of Boulder voted to impose an occupational tax to replace franchise fee revenues that would terminate when the franchise agreement terminated. In November 2011, two ballot measures were passed by the citizens of Boulder. The first measure increased the occupation tax to raise an additional $1.9 million annually for funding the exploration costs of forming a municipal utility and acquiring the PSCo electric distribution system in Boulder. The second measure authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage.

Boulder Staff have performed a feasibility study on municipalization and in July 2013, recommended that Boulder create its own electric utility. In August 2013, the Boulder City Council voted to authorize the acquisition of PSCo’s transmission and distribution system in and near Boulder. On Jan. 6, 2014, Boulder sent PSCo a Notice of Intent to Acquire (NOIA) for PSCo’s transmission, distribution and property assets within an area that includes Boulder and certain areas outside city limits. The NOIA is a legal prerequisite to the filing of an eminent domain proceeding in Colorado courts. However, sending the NOIA does not require Boulder to move forward with a condemnation case.

Boulder’s municipalization plan assumes that Boulder will acquire through condemnation PSCo facilities (and customers currently served from these PSCo facilities) that are located outside Boulder’s incorporated limits. PSCo petitioned the CPUC for a declaratory ruling that Boulder cannot serve PSCo’s customers outside Boulder’s city limits without obtaining a CPCN from the CPUC. The CPUC declared that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder’s city limits, and will determine what facilities need to be constructed to ensure reliable service. The CPUC stated it believes that the cost of all new facilities must be paid by Boulder. The CPUC declared that it should make its determinations prior to any eminent domain actions. On Jan. 15, 2014, Boulder appealed this ruling to Boulder District Court.

If Boulder commences an eminent domain proceeding, PSCo will seek to obtain full compensation for the business and its associated property taken by Boulder, as well as for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

RES Compliance Plan — Colorado law mandates that at least 30 percent of PSCo's energy sales are supplied by renewable energy by 2020 and includes a distributed generation standard. The CPUC has approved PSCo's 2012 and 2013 RES compliance plan to acquire up to 30 MW of customer-sited solar projects each year and up to 9 MW of community solar garden projects, which PSCo met in both 2012 and 2013. The CPUC also approved moving solely to a pay-for-performance basis under the Solar*Rewards distributed solar generation program, which PSCo implemented in 2012. Based on CPUC approval, PSCo implemented a solar gardens program called Solar*Rewards Community, which will allow customers to join together to own interests in a common solar facility and receive a credit related to their share of the solar garden's electric production on their electric bill. See Renewable Energy Sources for further discussion.

Table of Contents

In July 2013, PSCo filed its 2014 RES compliance plan which included continuing both the Solar*Rewards and Solar*Rewards Community programs, maintaining approximately the same capacity expected to be installed in 2013. PSCo also proposed to show in aggregate the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive." In December 2013, parties including the OCC filed answer testimony supporting PSCo's net metering proposal. However, rooftop solar advocates opposed it and also argued for higher solar installation levels and a slower reduction in incentives over time. Hearings are anticipated later in 2014 with a decision anticipated in the third quarter of 2014.

Steam System Package Boilers and Regulatory Plan — In December 2012, PSCo filed for a CPCN to construct two packaged boilers for its steam utility. The application also sought approval for PSCo's regulatory plan affecting rates for natural gas and steam services effective after the boilers have been placed in service. The proposed regulatory plan would combine the gas and steam revenue requirements for purposes of setting rates for retail gas and steam customers beginning January 2016.

In December 2013, the CPUC denied the application. The regulatory plan was designed to minimize customer attrition and the CPUC suggested that PSCo survey all steam customers in order to ensure that the boilers are appropriately sized before refiling.

Energy Source Statistics

	Year Ended Dec. 31								
	2013			2012			2011		
PSCo	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	19,647	56	%	21,367	59	%	22,065	61	%
Natural Gas	7,565	22		7,930	22		8,896	24	
Wind [(a)]	6,750	19		5,752	16		4,518	12	
Hydroelectric	655	2		590	2		681	2	
Other [(b)]	250	1		263	1		324	1	
Total	34,867	100	%	35,902	100	%	36,484	100	%
Owned generation	22,873	66	%	23,766	66	%	23,743	65	%
Purchased generation	11,994	34		12,136	34		12,741	35	
Total	34,867	100	%	35,902	100	%	36,484	100	%

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

(b) Includes energy from other sources, including nuclear, solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately 0.172, 0.133, and 0.137 net million KWh for 2013, 2012, and 2011, respectively.

Fuel Supply and Costs

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

	Coal			Natural Gas			Weighted
PSCo Generating Plants	Cost	Percent		Cost	Percent		Average Owned Fuel Cost
2013	$1.84	80	%	$4.86	20	%	$2.45
2012	1.77	78		4.25	22		2.31

2011	1.77	76	4.98	24	2.54

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

Fuel Sources

Coal — PSCo normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2013 and 2012 were approximately 41 and 46 days usage, respectively. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2013 and 2012, PSCo's coal requirements for existing plants were approximately 11.3 million tons. The estimated coal requirements for 2014 are approximately 10.5 million tons.

Table of Contents

PSCo has contracted for coal supply to provide 100 percent of its estimated coal requirements in 2014, and a declining percentage of requirements in subsequent years. PSCo's general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 100 percent of its coal requirements in 2014 and 2015. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company, the balance of natural gas supply contracts have pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 11 to the consolidated financial statements for further discussion. Most transportation contract pricing is based on FERC approved transportation tariff rates. These transportation rates are subject to revision based upon FERC approval of changes in the timing or amount of allowable cost recovery by providers. 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, 2013, PSCo's commitments related to gas supply contracts, which expire in various years from 2014 through 2023, were approximately $1.1 billion and commitments related to gas transportation and storage contracts, which expire in various years from 2014 through 2060, were approximately $723 million. At Dec. 31, 2012, PSCo's commitments related to gas supply contracts were approximately $1.1 billion and commitments related to gas transportation and storage contracts were approximately $754 million.

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

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2013, PSCo was in compliance with mandated RPS, which require generation from renewable resources of 12 percent of electric retail sales. Renewable energy comprised 21.9 percent and 18.4 percent of PSCo's total owned and purchased energy for 2013 and 2012, respectively. Wind energy comprised 19.3 percent and 16.0 percent of PSCo's total owned and purchased energy for 2013 and 2012, respectively. Hydroelectric, biomass and solar power comprised approximately 2.6 percent and 2.4 percent of PSCo's total owned and purchased energy for 2013 and 2012.

PSCo also offers customer-focused renewable energy initiatives. Windsource allows customers to purchase a portion or all of their electricity from renewable sources. In 2013, the number of customers increased to approximately 37,000 from 34,000 in 2012. Windsource MWh sales declined slightly, due in part to residential attrition, from approximately 201,000 MWh in 2012 to 197,000 MWh in 2013. 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 18,250 PV systems with approximately 188 MW of aggregate capacity and over 12,500 PV systems with approximately 138 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2013 and 2012, respectively.

Wind — PSCo acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Colorado. PSCo currently has 19 of these agreements in place, with facilities ranging in size from two MW to over 300 MW. In October 2013, the CPUC approved the addition of 450 MW of Colorado wind generation PPA's. In addition to receiving purchased wind energy under these agreements, PSCo also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under these contracts was approximately $45 and $47 for 2013 and 2012, 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 2013 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTC in 2013.

Additionally, PSCo owns and operates the 26 MW Ponnequin Wind Farm in northern Colorado, which has been in service since 1999. Collectively, PSCo had approximately 2,170 MW of wind energy on its system at the end of 2013 and 2012, respectively. With the new projects, PSCo is anticipated to have approximately 2,650 MW of wind power.

Table of Contents

Wholesale Commodity Marketing Operations

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

SPS
Public Utility Regulation

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

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

- DCRF — The DCRF rider recovers distribution costs in Texas.
- DRC — The DRC rider recovers deferred costs associated with renewable energy programs in New Mexico.
- EECRF — The EECRF rider recovers costs associated with providing energy efficiency programs in Texas.
- EE rider — The EE rider recovers costs associated with providing energy efficiency programs in New Mexico.
- FPPCAC — The FPPCAC adjusts monthly to recover the difference between the actual fuel and purchased power costs and the amount included in base rates of SPS' New Mexico retail jurisdiction.
- PCRF — The PCRF rider allows recovery of certain purchased power costs in Texas.
- TCRF — The TCRF rider recovers transmission infrastructure improvement costs and changes in wholesale transmission charges in Texas.

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

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

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

NMPRC regulations require SPS to request authority to continue collecting its fuel and purchased power costs through a fuel adjustment clause every four years. The NMPRC has granted SPS authority to use a fuel adjustment clause through November 2014.

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

Table of Contents

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2014, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2011	2012	2013	2014 Forecast
SPS	5,210	5,265	5,056	5,119

The peak demand for the SPS system typically occurs in the summer. The 2013 uninterrupted system peak demand for SPS occurred on Aug. 6, 2013. The 2013 peak demand is down slightly from the previous year, when peak weather conditions were hotter.

Energy Sources and Related Transmission Initiatives

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

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

In November 2013, the NMPRC approved SPS' request to enter into three PPAs for approximately 700 MW of additional wind power. These contracts were entered into by SPS for economic purposes, not to meet the state mandated renewable energy portfolios.

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

SPP Integrated Market (IM) — SPP has operated a regional energy imbalance market since 2007. SPS has recovered related charges and revenues in its retail and wholesale rates. In 2012 and 2013, the FERC approved proposed revisions to the SPP tariff to allow SPP to operate a day ahead/real time energy and ancillary services market similar to the regional market operated by MISO. The SPP IM is scheduled to start operations on March 1, 2014. SPS has submitted filings to the FERC to modify its wholesale power sales contracts to allow recovery of SPP IM charges and revenues through the SPP wholesale FCA. SPS has also requested FERC approval to make sales to the SPP IM at market-based rates. FERC approval of the tariff and market based rates filings are pending. SPS has also filed changes to its retail tariffs in Texas and New Mexico to allow retail FCA treatment of SPP IM charges and revenues.

SPS Transmission NTCs — As a member of SPP, SPS accepts NTCs for transmission projects. These are typically a portfolio of transmission lines and electric substation projects. SPS has accepted NTCs for several hundred miles of transmission lines and substations at an estimated capital cost of approximately $1.4 billion and will continue to review new NTCs for acceptance as they are issued. These projects generally span several years to plan, site, procure and develop. Typical SPS capital spending for SPP NTC transmission projects is approximately $200 to $300 million per year, but may vary. The NMPRC and the PUCT must approve the siting and routing of all SPP identified transmission line NTC projects that require permitting approval. Projects identified through SPP NTCs may have costs allocated to other SPP members in accordance with the SPP open access transmission tariff. Costs allocated to SPS are permissible for recovery through the NMPRC, the PUCT and the FERC processes.

TUCO Inc. (TUCO) to Woodward, Okla. 345 KV transmission line

The TUCO to Woodward District extra high voltage interchange is a 345 KV transmission line. SPS is constructing the line to just inside the Oklahoma state line, and Oklahoma Gas and Electric Company (OGE) is building from there to Woodward, Okla. SPS' estimated investment in the TUCO to Woodward line and substation is $185 million and is expected to be recovered from SPP members, including SPS, in accordance with the SPP OATT and the ratemaking process. The PUCT approved SPS' CCN to build the line in 2012. It is anticipated to be complete in mid-2014.

Hitchland substation to Woodward, Okla. 345 KV transmission line

The Hitchland substation to Woodward line is a 345 KV double circuit transmission line and associated substation facilities in the Oklahoma and Texas Panhandle. SPS is building the first 30 miles and OGE is completing the line from there to Woodward, Okla. SPS' estimated investment for the Hitchland to Woodward line and substation is $63 million and is expected to be recovered from SPP members in accordance with the SPP OATT and the ratemaking process. The line is anticipated to be complete in mid-2014.

Table of Contents

Jones CCN — In August 2011, the PUCT approved SPS' request for a CCN to build a gas-fired combustion turbine generating unit at SPS' existing Jones Station in Lubbock, Texas (Jones Unit 4). In February 2012, the NMPRC approved the CCN with a projected cost of $118 million, inclusive of AFUDC. Jones Unit 4 achieved commercial operation in May 2013 and added 168 MW of capacity to the SPS service territory.

SPS Resource Plans — SPS is required to develop and implement a renewable portfolio plan in which 10 percent of its energy to serve its New Mexico retail customers is produced by renewable resources in 2011, increasing to 15 percent in 2015. SPS primarily fulfills its renewable portfolio requirements through the purchase of wind energy. SPS was granted a variance from the NMPRC to extend the time to implement a portion of the diversity requirements to 2015.

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO_2 and NOx from utilities located in the eastern half of the United States. In December 2013, the U.S. Supreme Court heard oral arguments on the D.C. Circuit's 2012 decision to vacate the CSAPR. A decision is anticipated by June 2014. It is not yet known whether the D.C. Circuit's decision will be upheld, or how the EPA might approach a replacement rule. Therefore, it is not known what requirements may be imposed in the future. CSAPR is discussed further at Note 13 to the consolidated financial statements — Environmental Contingencies.

Energy Source Statistics

	Year Ended Dec. 31								
	2013			2012			2011		
SPS	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	14,184	49	%	14,005	49	%	14,818	48	%
Natural Gas	11,235	38		12,088	43		13,167	43	
Wind [(a)]	3,507	12		2,103	7		2,386	8	
Other [(b)]	167	1		177	1		409	1	
Total	29,093	100	%	28,373	100	%	30,780	100	%
Owned generation	18,814	65	%	19,940	70	%	19,310	63	%
Purchased generation	10,279	35		8,433	30		11,470	37	
Total	29,093	100	%	28,373	100	%	30,780	100	%

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

(b) Includes energy from other sources, including nuclear, hydroelectric, solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, was approximately 0.011, 0.008, and 0.006 net million KWh for 2013, 2012, and 2011, respectively.

Fuel Supply and Costs

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

	Coal			Natural Gas			Weighted Average
SPS Generating Plants	Cost	Percent		Cost	Percent		Owned Fuel Cost
2013	$2.14	71	%	$3.97	29	%	$2.68
2012	1.87	67		2.99	33		2.24
2011	1.89	67		4.37	33		2.71

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

Table of Contents

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers. The coal supply contract with TUCO expires in 2016 and 2017 for the Harrington station and Tolk station, respectively. As of Dec. 31, 2013 and 2012, coal inventories at SPS were approximately 42 and 40 days supply, respectively. TUCO has coal agreements to supply 93 percent of SPS' estimated coal requirements in 2014, and a declining percentage of the requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years.

Natural gas — SPS uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel; which typically is purchased with terms of one year or less. The transportation and storage contracts expire in various years from 2014 to 2033. All of the natural gas supply contracts have pricing that is tied to various natural gas indices.

Most transportation contract pricing is based on FERC and Railroad Commission of Texas approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. SPS' commitments related to gas supply contracts were approximately $21 million and $57 million and commitments related to gas transportation and storage contracts were approximately $201 million and $229 million at Dec. 31, 2013 and 2012, respectively.

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

Renewable Energy Sources

SPS' renewable energy portfolio includes wind and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2013, SPS is in compliance with mandated RPS, which require generation from renewable resources of approximately four percent and 10 percent of Texas and New Mexico electric retail sales, respectively. Renewable energy comprised 12.7 percent and 8.0 percent of SPS' total owned and purchased energy for 2013 and 2012, respectively. Wind energy comprised 12.1 percent and 7.4 percent of SPS' total owned and purchased energy for 2013 and 2012, respectively. Solar power comprised approximately 0.4 percent and 0.5 percent of SPS' total owned and purchased energy for 2013 and 2012, respectively.

SPS also offers customer-focused renewable energy initiatives. Windsource allows customers in New Mexico to purchase a portion or all of their electricity from renewable sources. The number of Windsource participants dropped from approximately 1,000 in 2012 to 900 in 2013 due to residential attrition, while Windsource MWh sales remained consistent from approximately 4,400 MWh in 2012 to 4,400 MWh in 2013. Additionally, to encourage the growth of solar energy on the system in New Mexico, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 115 PV systems with approximately 7.6 MW of aggregate capacity and over 80 PV systems with approximately 4.5 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2013 and 2012, respectively.

Wind — SPS acquires its wind energy from long-term PPAs with wind farm owners, primarily located in the Texas Panhandle area of Texas and New Mexico. SPS currently has six of these agreements in place, with facilities ranging in size from under two MW to 161 MW for a total capacity greater than 600 MW. In 2013, the NMPRC approved three PPAs for approximately 700 MW of wind power. In addition to receiving purchased wind energy under these agreements, SPS also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under the PPA and QF contracts was approximately $26 for each of 2013 and 2012. 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 2013 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2013. At the end of each of 2013 and 2012, SPS had over 1,000 MW of wind energy on its system. With these projects, SPS is anticipated to have approximately 1,800 MW of wind power.

Wholesale Commodity Marketing Operations

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

Table of Contents

Summary of Recent Federal Regulatory Developments

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

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — The FERC issued Order 1000 in July 2011 adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. In Order 1000, the FERC required utilities, including RTO's such as MISO and SPP, to file compliance tariffs that provide for joint regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region. In addition, Order 1000 required that regions coordinate to develop interregional plans for transmission planning and cost allocation. A key provision of Order 1000 is a requirement that FERC-jurisdictional wholesale transmission tariffs exclude provisions that would grant the incumbent transmission owner a federal ROFR to build certain types of transmission projects in its service area. Various parties have appealed Order 1000 final rules to the D.C. Circuit. NSP-Minnesota and NSP-Wisconsin are participating in the appeals in coordination with other MISO transmission owners and utilities who oppose certain aspects of the rules, including the ROFR prohibition. Briefs have been filed by parties challenging the final rules, by the FERC and by parties supporting the final rules. Oral arguments are scheduled March 20, 2014. The date for a Court ruling is uncertain.

The removal of a federal ROFR would eliminate rights that NSP-Minnesota, NSP-Wisconsin and SPS currently have under the MISO and SPP tariffs to build certain transmission projects within their footprints. The FERC required that the opportunity to build such projects would extend to competitive transmission developers. Compliance with Order 1000 for NSP-Minnesota and NSP-Wisconsin will occur through changes to the MISO tariff while compliance for SPS will occur through the SPP tariff. PSCo is not in an RTO and therefore is responsible for making its own Order 1000 compliance filings. MISO, SPP and PSCo all made their initial compliance filings to incorporate new provisions into their tariffs regarding regional planning and cost allocation. The FERC ruled on the initial regional compliance filings for MISO, SPP and PSCo, and directed further changes to fully address the requirements of Order 1000. Additional regional compliance filings have been submitted by MISO, SPP, PSCo and FERC action on these supplemental compliance filings is pending. Several parties, including Xcel Energy, also sought rehearing of the FERC orders requiring changes to the initial compliance filings. The rehearing requests are also pending FERC action.

Filings to address Order 1000 interregional planning and cost allocation requirements with other regions were made by PSCo, MISO and SPP in 2013. The filings are pending action by the FERC.

NSP-System

In 2012, Minnesota enacted legislation that preserves ROFR rights for Minnesota utilities at the state level. This legislation is similar to legislation previously passed in North Dakota and South Dakota. Wisconsin has not developed such legislation. The FERC's initial order to address the regional requirements of Order 1000 required MISO to remove proposed tariff provisions that would have recognized state ROFR rights and allowed state regulators to select the developer of a transmission project. NSP-Minnesota, NSP-Wisconsin and other MISO transmission owners requested rehearing of this issue. The rehearing request is pending the FERC's action. The FERC has accepted changes to MISO's transmission cost allocation procedures that will protect the ROFR for projects needed for system reliability.

PSCo

Colorado does not have legislation protecting ROFR rights for incumbent utilities. PSCo submitted its compliance filing to address the regional planning and cost allocation requirements of Order 1000, proposing that PSCo would join the WestConnect region, a consortium of utilities in the Western Interconnection. In March 2013, the FERC issued its order on PSCo’s initial compliance filing and required a further compliance filing with additional tariff changes. In April 2013, PSCo and other WestConnect members requested rehearing on various aspects of the March 2013 order. PSCo and other WestConnect jurisdictional utilities made their additional compliance filings to address directives in the March 2013 order. The FERC is expected to rule in 2014 on the regional compliance filing and the requests for rehearing. WestConnect members, including PSCo, filed their Order 1000 interregional compliance filings in May 2013 and the filings are pending FERC action.

Table of Contents

SPS

In July 2013, the FERC issued its initial order on SPP's Order 1000 regional compliance filing identifying several issues and requiring a further compliance filing by SPP. The FERC rejected SPP's proposal to retain a ROFR for new transmission projects with operational voltages between 100 KV and 300 KV. Requests for rehearing of the FERC's July 2013 order were filed and are pending FERC action. The SPP regional compliance filing to the July 2013 order was filed and is pending FERC action. The SPP interregional compliance filing was submitted and is also pending the FERC's action. SPS believes that Texas statutes protect the ROFR of incumbent utilities operating outside of the Electric Reliability Council of Texas (ERCOT) to construct and own transmission interconnected to their systems, though this view is disputed by some parties. The State of New Mexico does not have legislation protecting ROFR rights for incumbent utilities.

Xcel Energy Services Inc. and NSP-Wisconsin vs. ATC (La Crosse, Wis. to Madison, Wis. Transmission Line) — In February 2012, Xcel Energy Services Inc. and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. In July 2012, the FERC ruled favorably on Xcel Energy Services Inc.'s and NSP-Wisconsin's complaint, ruling that the responsibilities to construct the La Crosse, Wis. to Madison, Wis. transmission line, also known as the Badger Coulee line, belong equally to NSP-Wisconsin and ATC. In August 2012, ATC requested rehearing and requested that the FERC grant a stay of the ruling. In September 2012, the FERC granted rehearing for purposes of further consideration but did not grant a stay. Thus, the July ruling remains in effect pending the FERC's further ruling on rehearing. In order to proceed with development of the project, the two companies are working together on routing and regulatory state issues pending FERC action on ATC's request for rehearing. A joint CPCN application was filed with the PSCW in October 2013.

ATC vs. Xcel Energy Services Inc. and MISO (Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. Transmission Line) — In October 2012, ATC filed a complaint against MISO, Xcel Energy Services Inc., NSP-Minnesota and NSP-Wisconsin, alleging that, under the legal principles set forth in the July 2012 FERC ruling in the La Crosse, Wis. to Madison, Wis. transmission line complaint filed by Xcel Energy Services Inc. and NSP-Wisconsin against ATC, that the FERC should determine that MISO should have designated the Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. CapX2020 line and the La Crosse, Wis. to Madison, Wis. line as a single facility under the MISO Transmission Owners Agreement and Tariff. Thus, ATC should have been designated as the owner of the La Crosse, Wis. to Madison, Wis. line portion of the purported single facility. Xcel Energy filed an answer seeking dismissal of the ATC complaint in October 2012. On Feb. 4, 2013, the FERC issued an order denying the ATC complaint. The FERC found that MISO properly applied its planning process and that Hampton, Minn. to La Crosse, Wis. and the La Crosse, Wis. to Madison, Wis. lines are separate. ATC did not seek rehearing and therefore the FERC order is final and MISO's prior ownership decisions stand, which brings this matter to a close.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments depending on whether the project is primarily local or regional in nature. If a project qualifies as a MVP, the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 KV and higher) projects expected to serve multiple purposes such as improved reliability, reduced congestion, transmission for renewable energy and load serving. Certain parties appealed the FERC MVP tariff orders to the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit). In June 2013, the Seventh Circuit upheld the FERC MVP tariff orders allocating MVP project costs regionally, but remanded the FERC decision to not apply the regional charge to transmission service transactions crossing into the PJM RTO. U.S. Supreme Court review of the Seventh Circuit decision has been requested and the response is pending. The NSP System has certain new transmission facilities for which other customers in MISO contribute to cost recovery. Likewise, the NSP System also pays a share of the costs of projects constructed by other transmission owning entities. The transmission revenues received by the NSP System from MISO and the transmission charges paid to MISO associated with projects subject to regional cost allocation could be significant in future periods.

RSG Charges — The MISO tariff charges certain market participants a real-time RSG charge, designed to ensure that any generator scheduled or dispatched by MISO receives no less than its offer price for start-up, no-load and incremental energy. In August 2010, the FERC issued two orders relating to RSG charge exemptions and the allocation of the RSG costs among MISO participants. The FERC has allowed allocating a greater portion of the RSG costs related to resources committed for voltage and local reliability requirements to the market participants serving the loads that benefit from such commitments. Certain of the FERC's orders remain pending on rehearing. An appeal to the D.C. Circuit has been held in abeyance, pending the FERC's disposition of rehearing requests. If the FERC were to reverse or modify the prior orders on rehearing, the NSP system could be subject to additional RSG charges for prior periods. NSP-Minnesota is permitted to recover the RSG costs through FCA mechanisms. NSP-Wisconsin recovers RSG costs in its fuel and purchased energy recovery mechanism in Wisconsin and through its power supply cost recovery mechanism in Michigan.

Table of Contents

MISO ROE Complaint — In November 2013, a group of customers filed a complaint at the FERC against all FERC jurisdictional MISO transmission owners, including NSP-Minnesota and NSP-Wisconsin. The complaint argues for a reduction in the ROE applicable to transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013. In January 2014, Xcel Energy Services, Inc. filed an answer to the complaint asserting that the 9.15 percent ROE would be unreasonable and that the complainants failed to demonstrate the NSP System equity capital structure was unreasonable. The MISO Transmission Owners separately answered the complaint, arguing the complainants do not have standing to challenge the MISO Tariff provisions, have not met their burden of proof to demonstrate that the current FERC-approved ROE, capital structure and other incentives are unjust and unreasonable, and the complaint should be dismissed. Other parties filed comments supporting a reduction in the MISO regional ROE, the equity capital structure limitations, and limits on ROE incentives, and supported the proposed effective date. In January 2014, the complainants filed an answer to the MISO Transmission Owners' motion to dismiss. The complaint is pending FERC action. The estimated impact of FERC granting the complaint could amount to a reduction of revenue of $11.7 million annually for NSP-Minnesota and NSP-Wisconsin. NSP-Minnesota and NSP-Wisconsin would seek to offset any reduction in wholesale revenues through increases in retail rates.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2013	2012	2011
Electric sales (Millions of KWh)			
Residential	25,306	25,033	25,278
Large commercial and industrial	27,206	27,396	27,419
Small commercial and industrial	35,873	35,660	35,597
Public authorities and other	1,098	1,109	1,135
Total retail	89,483	89,198	89,429
Sales for resale	15,065	15,781	20,177
Total energy sold	104,548	104,979	109,606
Number of customers at end of period			
Residential	2,965,717	2,940,024	2,919,660
Large commercial and industrial	1,132	1,147	1,129
Small commercial and industrial	422,553	419,618	415,755
Public authorities and other	67,998	68,510	69,350
Total retail	3,457,400	3,429,299	3,405,894
Wholesale	65	75	78
Total customers	3,457,465	3,429,374	3,405,972
Electric revenues (Thousands of Dollars)			
Residential	$2,906,208	$2,713,575	$2,712,340
Large commercial and industrial	1,694,720	1,534,728	1,616,596
Small commercial and industrial	3,248,586	3,023,154	3,025,416
Public authorities and other	138,126	130,538	129,826
Total retail	7,987,640	7,401,995	7,484,178
Wholesale	693,728	687,912	936,875
Other electric revenues	352,677	427,389	345,540
Total electric revenues	$9,034,045	$8,517,296	$8,766,593

KWh sales per retail customer	25,882		26,011		26,257	
Revenue per retail customer	$2,310		$2,158		$2,197	
Residential revenue per KWh	11.48	¢	10.84	¢	10.73	¢
Large commercial and industrial revenue per KWh	6.23		5.60		5.90	
Small commercial and industrial revenue per KWh	9.06		8.48		8.50	
Total retail revenue per KWh	8.93		8.30		8.37	
Wholesale revenue per KWh	4.60		4.36		4.64	

Table of Contents

Energy Source Statistics

	Year Ended Dec. 31								
	2013			2012			2011		
Xcel Energy	Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation		Millions of KWh	Percent of Generation	
Coal	49,675	46	%	51,395	47	%	57,014	50	%
Natural Gas	24,350	23		26,218	24		25,080	22	
Wind [(a)]	15,738	14		13,298	12		11,216	10	
Nuclear	12,177	11		13,249	12		13,781	12	
Hydroelectric	3,900	4		3,800	3		4,203	4	
Other [(b)]	1,704	2		2,022	2		1,659	2	
Total	107,544	100	%	109,982	100	%	112,953	100	%
Owned generation	70,936	66	%	75,071	68	%	74,722	66	%
Purchased generation	36,608	34		34,911	32		38,231	34	
Total	107,544	100	%	109,982	100	%	112,953	100	%

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

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately 0.198, 0.152, and 0.146 net million KWh for 2013, 2012 and 2011, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of the utility subsidiaries are continued volatility in natural gas market prices, uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2013, average annual sales to the typical residential customer declined 17 percent and the typical small commercial and industrial customer declined 11 percent on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law in January 2012 (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure if records are inadequate. This process could cause temporary or permanent limitations on throughput for affected pipelines. In addition, the Pipeline Safety Act requires PHMSA to issue reports and develop new regulations including: requiring use of automatic or remote-controlled shut-off valves; requiring testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to $2 million per day for related violations. While Xcel Energy cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, it is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA rider.

Table of Contents

NSP-Minnesota
Public Utility Regulation

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

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation service and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period. 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 767,636 MMBtu, which occurred on Jan. 21, 2013 and 732,135 MMBtu, which occurred on Jan. 19, 2012.

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 596,411 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 31 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 31 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. Contract demand levels for the past five years are being reviewed by the MPUC.

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:

2013	$4.53
2012	4.41
2011	5.25

Table of Contents

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2014 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, 2013, NSP-Minnesota was committed to approximately $356 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 28 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

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

NSP-Wisconsin
Public Utility Regulation

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

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

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

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 155,087 MMBtu, which occurred on Jan. 21, 2013, and 143,134 MMBtu, which occurred on Jan. 19, 2012.

NSP-Wisconsin purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 132,591 MMBtu per day. In addition, NSP-Wisconsin contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 39 percent of peak day firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent and one propane-air plant with a storage capacity of 2,700 Mcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 18,408 MMBtu of natural gas per day, or approximately 13 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2013-2014 supply plan was approved by the PSCW in November 2013.

Natural Gas Supply and Costs

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

Table of Contents

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

2013	$4.51
2012	4.36
2011	5.18

The cost of natural gas supply, transportation service and storage service is recovered through various cost-recovery adjustment mechanisms. NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2014 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2013, NSP-Wisconsin was committed to approximately $82 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 13 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

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

PSCo
Public Utility Regulation

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

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

- GCA — The GCA recovers the actual costs of purchased natural gas and transportation to meet the requirements of its customers and is revised quarterly to allow for changes in natural gas rates.
- DSMCA — The DSMCA is a low-income energy assistance program. The costs of this energy conservation and weatherization program are recovered through the gas DSMCA.
- PSIA — Effective Jan. 1, 2012, the PSIA began to recover costs associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines. Although PSCo had proposed to include the PSIA in base rates, instead the rider was extended through Dec. 31, 2015.

QSP Requirements — The CPUC established a natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service. The CPUC conducts proceedings to review and approve the rate adjustment annually. In 2013, the CPUC extended the terms of the current QSP through the end of 2015.

Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation to be 1,952,939 MMBtu. In addition, firm transportation customers hold 797,329 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,750,268 MMBtu per day. The maximum daily deliveries for

PSCo for firm and interruptible services were 1,865,207 MMBtu on Dec. 5, 2013 and 1,539,864 MMBtu on Dec. 19, 2012.

Table of Contents

PSCo purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,822,939 MMBtu per day, which includes 859,514 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide approximately 22,400 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo’s city gate meter stations.

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

Natural Gas Supply and Costs

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

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

2013	$4.20
2012	4.28
2011	4.99

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2013, PSCo was committed to approximately $2.0 billion in such obligations under these contracts, which expire in various years from 2014 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2013, PSCo purchased natural gas from approximately 40 suppliers.

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

SPS

Natural Gas Facilities Used for Electric Generation

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

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

Table of Contents

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2013	2012	2011
Natural gas deliveries (Thousands of MMBtu)			
Residential	150,280	123,835	139,200
Commercial and industrial	92,849	77,848	86,788
Total retail	243,129	201,683	225,988
Transportation and other	125,057	116,611	117,654
Total deliveries	368,186	318,294	343,642
Number of customers at end of period			
Residential	1,776,849	1,760,364	1,747,153
Commercial and industrial	154,646	154,158	153,911
Total retail	1,931,495	1,914,522	1,901,064
Transportation and other	6,320	5,789	5,395
Total customers	1,937,815	1,920,311	1,906,459
Natural gas revenues (Thousands of Dollars)			
Residential	$1,126,859	$964,642	$1,133,888
Commercial and industrial	586,548	488,644	601,298
Total retail	1,713,407	1,453,286	1,735,186
Transportation and other	91,272	84,088	76,740
Total natural gas revenues	$1,804,679	$1,537,374	$1,811,926
MMBtu sales per retail customer	125.88	105.34	118.87
Revenue per retail customer	$887	$759	$913
Residential revenue per MMBtu	7.50	7.79	8.15
Commercial and industrial revenue per MMBtu	6.32	6.28	6.93
Transportation and other revenue per MMBtu	0.73	0.72	0.65

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

Competition

Xcel Energy remains a vertically integrated utility in all of its jurisdictions subject to traditional cost-of-service regulation by state public utilities commissions. Within this construct, however, Xcel Energy is subject to different public policies that promote competition and the development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with on-site solar generation (typically rooftop solar) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Table of Contents

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. Several states have policies designed to promote the development of solar and other distributed energy resources through significant incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business. These competitive challenges continue to evolve over time. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with currently available alternatives. Xcel Energy continues to evaluate policies, products and strategies to enable it to compete in the changing energy marketplace.

ENVIRONMENTAL MATTERS

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

There are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. While environmental regulations related to climate change and clean energy continue to evolve, Xcel Energy has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Although the impact of these policies on Xcel Energy will depend on the specifics of state and federal policies, legislation, and regulation, we believe that, based on prior state commission practice, we would recover the cost of these initiatives through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Xcel Energy adopted a methodology for calculating CO_2 emissions based on the reporting protocols of The Climate Registry, a nonprofit organization that provides and compiles GHG emissions data from reporting entities. Starting in 2011, Xcel Energy began reporting GHG emissions to the EPA under the EPA's mandatory GHG Reporting Program. Currently, EPA reporting rules do not address REC transactions. It is not clear whether future GHG reporting regulations could require reporting of CO_2 emissions for REC transactions.

Based on The Climate Registry's current reporting protocol, Xcel Energy estimated that its current electric generating portfolio, which includes owned coal- and gas-fired plants, emitted approximately 57.1 million and 59.2 million tons of CO_2 in 2013 and 2012, respectively. Xcel Energy also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates these non-owned facilities emitted approximately 14.1 million and 14.5 million tons of CO_2 in 2013 and 2012, respectively. Estimated total CO_2 emissions associated with service to Xcel Energy electric customers decreased by 2.5 million tons in 2013 compared to 2012. The decrease in emissions was associated with a decrease of 5.4 million MWh of generation since 2011. The average annual decrease in CO_2 emissions since 2011 is approximately 3.6 million tons of CO_2 per year.

CAPITAL SPENDING AND FINANCING

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

Table of Contents

EMPLOYEES

As of Dec. 31, 2013, Xcel Energy had 11,457 full-time employees and 124 part-time employees, of which 5,587 were covered under collective-bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

EXECUTIVE OFFICERS

Benjamin G.S. Fowke III, 55, Chairman of the Board, President and Chief Executive Officer, Xcel Energy Inc., August 2011 to present. Previously, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to August 2011; Executive Vice President and Chief Financial Officer, Xcel Energy Inc., December 2008 to August 2009; Vice President and Chief Financial Officer, Xcel Energy Inc., May 2004 to December 2008; Vice President, Chief Financial Officer and Treasurer, Xcel Energy Inc., October 2003 to May 2004; Vice President and Treasurer, Xcel Energy Inc., November 2002 to October 2003; and Vice President and Chief Financial Officer, Energy Markets Business Unit, Xcel Energy Services Inc., August 2000 to November 2002.

David L. Eves, 55, President, Director and Chief Executive Officer, PSCo, December 2009 to present. Previously, President, Director and Chief Operating Officer, PSCo, November 2009 to December 2009; President and Director, SPS, December 2006 to November 2009; Chief Executive Officer, SPS, August 2006 to November 2009; Vice President of Resource Planning and Acquisition, Xcel Energy Services Inc., November 2002 to July 2006; and Managing Director, Resource Planning and Acquisition, Xcel Energy Services Inc., August 2000 to November 2002.

David T. Hudson, 53, President, Director and Chief Executive Officer, SPS, January 1, 2014 to present. Previously, Director, Community Service & Economic Development, SPS, April 2011 to January 2014; Director, Strategic Planning, SPS, May 2008 to April 2011; and Director, Regulatory Administration, SPS, August 2000 to May 2008; Director, Electric Retail/Wholesale Services, SPS, May 1997 to August 2000.

Kent T. Larson, 54, Senior Vice President, Operations, Xcel Energy Services Inc., September 2011 to present. Previously, Chief Energy Supply Officer, Xcel Energy Services Inc., March 2010 to September 2011; Vice President, Transmission, Xcel Energy Services Inc., August 2008 to March 2010; Regional Vice President, Xcel Energy Services Inc., February 2006 to August 2008; Vice President, Jurisdictional Relations, Xcel Energy Services Inc., April 2004 to February 2006; and State Vice President, NSP-Minnesota, September 2000 to April 2004.

Teresa S. Madden, 58, Senior Vice President, Chief Financial Officer, Xcel Energy Inc., September 2011 to present. Previously, Vice President and Controller, Xcel Energy Inc., January 2004 to September 2011; Vice President of Finance, Customer and Field Operations Business Unit, Xcel Energy Inc., August 2003 to January 2004; Interim Chief Financial Officer, Rogue Wave Software, Inc., February 2003 to July 2003; and Corporate Controller, Rogue Wave Software, Inc., October 2000 to February 2003.

Marvin E. McDaniel, Jr., 54, Senior Vice President, Chief Administrative Officer, Xcel Energy Inc., August 2012 to present. Previously, Senior Vice President and Chief Administrative Officer, Xcel Energy Services Inc., September 2011 to August 2012; Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August 2009 to September 2011 and Vice President, Talent and Technology Business Areas, Xcel Energy Services Inc., August 2009 to September 2011; Vice President, Human Resources, Xcel Energy Services Inc., July 2007 to August 2009; Vice President and Assistant Controller, Xcel Energy Services Inc., March 2005 to June 2007; and Vice President and Controller Energy Markets Business Unit, Xcel Energy Services Inc., February 2004 to February 2005.

Timothy O’Connor, 54, Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc., February 2013 to present. Previously, Acting Chief Nuclear Officer, NSP-Minnesota, September 2012 to February 2013; Vice

President, Engineering and Nuclear Regulatory Compliance and Licensing July 2012 to September 2012; Monticello Site Vice President in May 2007 to July 2012; Site Vice President and plant manager, Nine Mile Point Station, Constellation Energy, 2004 to May 2007; and corporate and site responsibilities at Public Service Enterprise Group, Hope and Salem plants, between the years of 1999 to 2004.

R. Roy Palmer, 55, Senior Vice President, External Affairs, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President, Federal and State Government Affairs, Xcel Energy Services Inc., January 2009 to September 2011; Managing Director, Government and Regulatory Affairs, Xcel Energy Services, Inc., November 2007 to January 2009; Executive Director, State Public Affairs, Xcel Energy Services Inc., April 2005 to November 2007; and Director, Regional Government Affairs, Xcel Energy Services Inc., March 2004 to April 2005.

Table of Contents

Judy M. Poferl, 54, Vice President, Corporate Secretary, Xcel Energy Inc., May 2013 to present. Previously, President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to May 2013; Regional Vice President, NSP-Minnesota, September 2008 to August 2009; Managing Director, Government and Regulatory Affairs, Xcel Energy Services Inc., November 2007 to September 2008; and Director, Regulatory Administration, Xcel Energy Services Inc., August 2000 to November 2007.

Jeffrey S. Savage, 42, Vice President, Controller, Xcel Energy Inc., September 2011 to present. Previously, Senior Director, Financial Reporting, Corporate and Technical Accounting, Xcel Energy Services Inc., December 2009 to September 2011; Director, Financial Reporting and Technical Accounting, Xcel Energy Services Inc., March 2007 to December 2009; and Director, Financial Reporting and Technical Accounting, The Mosaic Company, January 2006 to March 2007.

David M. Sparby, 59, Senior Vice President, Group President, Xcel Energy Services Inc. and President, Director and Chief Executive Officer, NSP-Minnesota, May 2013 to present. Previously, Senior Vice President, Group President, Xcel Energy Services Inc, September 2011 to May 2013; Vice President and Chief Financial Officer, Xcel Energy Inc., August 2009 to September 2011; President, Director and Chief Executive Officer, NSP-Minnesota, August 2008 to August 2009; Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to August 2008; and Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

Mark E. Stoering, 53, President, Director and Chief Executive Officer, NSP-Wisconsin, January 2012 to present. Previously, Vice President, Portfolio Strategy and Business Development, Xcel Energy Services Inc., August 2000 to December 2011.

George E. Tyson, II, 48, Vice President, Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy Inc., July 2003 to May 2004; Director of Origination, Energy Markets Business Unit, Xcel Energy Services Inc., May 2002 to July 2003; and Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

Scott M. Wilensky, 57, Senior Vice President, General Counsel, Xcel Energy Inc., September 2011 to present. Previously, Vice President, Regulatory and Resource Planning, Xcel Energy Services Inc., September 2009 to September 2011; Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., August 2008 to September 2009; Executive Director, Revenue, Xcel Energy Services Inc., March 2006 to August 2008; Director, State Public Affairs, Xcel Energy Services Inc., November 2001 to March 2006; Assistant General Counsel, Xcel Energy Services Inc., August 2001 to November 2001; and Senior Attorney, Xcel Energy Services Inc., December 1998 to August 2001.

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

Item 1A — Risk Factors

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

There may be further risks and uncertainties that are not presently known or are not currently believed to be material that may adversely affect our performance or financial condition in the future.

Oversight of Risk and Related Processes

The goal of Xcel Energy's risk management process is to understand, manage and, when possible, mitigate material risk. Management is responsible for identifying and managing risks, while the Board of Directors oversees and holds management accountable. Xcel Energy is faced with a number of different types of risk. Many of these risks are cross-cutting risks such that these risks are discussed and managed across business areas and coordinated by Xcel Energy's senior management. Our risk management process has three parts: identification and analysis, management and mitigation and communication and disclosure.

Table of Contents

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 economy and the environment to identify risks. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Management seeks to mitigate the risks inherent in the implementation of Xcel Energy's strategy. 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. At a threshold level, Xcel Energy has developed a robust compliance program and promotes a culture of compliance, including tone at the top, which mitigates risk. Building on this culture of compliance, Xcel Energy manages and further mitigates risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of corporate areas such as internal audit, the corporate controller and legal services. While Xcel Energy has developed a number of formal structures for risk management, many material risks affect the business as a whole and are managed across business areas.

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

The guidelines on corporate governance and Board committee charters define the scope of review and inquiry for the Board and its committees. Each Board committee has responsibility for overseeing aspects of risk and Xcel Energy's management and mitigation of the risk. The Board of Directors has overall responsibility for risk oversight and with the committees periodically undertakes the review of the charters to ensure that oversight of key risks are appropriately considered by the various Board committees. The Board also reviews risks at an enterprise level and annually conducts a full day strategy session where it considers risks and confirms that Xcel Energy's strategy appropriately addresses risk management and mitigation and reviews the performance and annual goals of each business area.

As described above, the Board reviews senior management's key risk assessment that analyzes the most likely areas of future risk to Xcel Energy. This review, when combined with the oversight of specific risks by the committees, allows the Board to confirm risk is considered in the development of goals and that risk has been adequately considered and mitigated in the execution of corporate strategy. The presentation of the assessment of key risks also provides the basis for the discussion of risk in our public filings and securities disclosures.

Table of Contents

Risks Associated with Our Business

Environmental Risks

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

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental requirements including those for protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archaeological and historical resources), licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, install pollution control equipment at our facilities, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities, either due to the difficulty in assuring compliance or that the costs of compliance no longer makes operation of the units economic. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e., cleanup) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2013, these sites included:

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

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

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

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

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. We do not serve any coastal communities so the possibility of sea level rises does not directly affect us or our customers.

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 depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers.

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

Table of Contents

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on GHGs or additional environmental regulation could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Financial Risks

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

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

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

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

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

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. For example, Standard & Poor's calculates an imputed debt associated with capacity payments from purchased power contracts. An increase in the overall level of capacity payments would increase the amount of imputed debt, based on Standard & Poor's methodology. Therefore, Xcel Energy Inc. and its subsidiaries credit ratings could be adversely affected based on the level of capacity payments associated with purchased power contracts or changes in how our imputed debt is determined. Any downgrade could lead to higher borrowing costs. Also, our utility subsidiaries may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

Table of Contents

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment in property, plant and equipment; consequently, we are an active participant in debt and equity 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 or on incremental commercial paper issuances could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning fund and master pension trust, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

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

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

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires broad clearing of financial swap transactions through a central counterparty, which could lead to additional margin requirements that would impact our liquidity: however, we have taken advantage of an exception to mandatory clearing afforded to commercial end-users who are not classified as a major swap participant. The Board of Directors has authorized Xcel Energy and its subsidiaries to take advantage of this end-user exception. In addition, the CFTC has granted an increase in the de minimis level for swap transactions with defined utility special entities, generally entities owning or operating electric or natural gas facilities, from $25 million to $800 million. Our current level of financial swap activity with special entities is significantly below this new threshold; therefore, we will not be classified as a swap dealer in our special entity activity. Swap transactions with non special entities have a much higher level of activity considered to be de minimis, currently $8 billion, and our level of activity is well under this limit; therefore, we will not be classified as a swap dealer under the Dodd-Frank Act. We are currently reporting all of our swap transactions as part of the Dodd-Frank Act.

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

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

Table of Contents

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

We have defined benefit pension and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans with modifications to these funding requirements that allowed additional flexibility in the timing of contributions. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

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 and costs for retiree health care plans have increased substantially 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. Legislation related to health care could also significantly change our benefit programs and costs.

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

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

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

Operational Risks

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

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

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

Table of Contents

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

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

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of these radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

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

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

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

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

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

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

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

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

Table of Contents

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 additional verification of pipeline infrastructure records by intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

Public Policy Risks

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

Increased public awareness and concern regarding climate change may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHGs, and federal legislation has been introduced in both houses of Congress. The U.S. continues to participate in international negotiations related to the United Nations Framework Convention on Climate Change. Such 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 regulation under climate change laws at either the state or federal level in the future. The EPA is regulating GHGs under the CAA. The EPA has regulated GHG emissions from motor vehicles and adopted new permitting requirements for GHG emissions of new and modified large stationary sources, which are applicable to construction of new power plants or power plant modifications that increase emissions above a certain threshold. The EPA has proposed regulations that would establish NSPS for any new fossil fuel-fired power plants that may be built. If adopted, these regulations could significantly increase the cost of building new generating plants. By 2016, the EPA plans to develop and implement GHG regulations applicable to emissions from existing power plants. Such regulations could impose substantial costs on our system.

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

There are many uncertainties regarding when and in what form climate change legislation or regulations may be enacted. The impact of legislation and regulations will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are recognized as compliance options, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the U.S., any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us. 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, ash management and cooling water intake systems. The costs of investment to comply with these rules could be substantial. 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 $1 million per violation per day. In addition, NERC electric reliability standards are now mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. If a serious reliability incident did occur, it could have a material effect on our operations or financial results.

Table of Contents

The FERC issued NOVs of its market manipulation rules to several market participants during 2013. The potential penalties in one pending case exceed $400 million. We attempt to mitigate this risk 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 could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged economic recession and uncertainty of recovery has lowered the correlation between sales and economic growth. Sales growth has been relatively flat due to lower level of economic activity, increased focus on energy efficiency and distributed generation. Instability in the financial markets also may affect the cost of capital and our ability to raise capital, which are discussed in greater detail in the capital market risk section above.

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

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

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

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

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

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

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

Table of Contents

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

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

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (e.g., information about our customers, employees, operations, infrastructure and assets) could be directly or indirectly affected by unintentional or deliberate 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, we also anticipate that such an event would receive regulatory scrutiny at both the Federal and State level. We are unable to quantify the potential impact of such 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.

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

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

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

Item 1B — Unresolved Staff Comments

None.

48

Table of Contents

Item 2 — Properties

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

Electric Utility Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	Summer 2013 Net Dependable Capability (MW)	
Steam:				
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511	
Sherco-Becker, Minn.				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	507	(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	554	
Prairie Island-Welch, Minn.				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Black Dog-Burnsville, Minn., 2 Units	Coal/Natural Gas	1955-1960	232	
Various locations, 4 Units	Wood/Refuse-derived fuel	Various	36	(b)
Combustion Turbine:				
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327	
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	271	
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453	
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	534	
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470	
Various locations, 17 Units	Natural Gas	Various	101	
Wind:				
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101	(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201	(c)
		Total	6,982	

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

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

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

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2013 Net Dependable Capability (MW)	
Steam:				
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	56	
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	16	(a)
Combustion Turbine:				
Flambeau Station-Park Falls, Wis., 1 Unit	Natural Gas	1969	12	
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	122	
Wheaton-Eau Claire, Wis., 6 Units	Natural Gas	1973	290	

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

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

Table of Contents

PSCo

Station, Location and Unit	Fuel	Installed	Summer 2013 Net Dependable Capability (MW)	
Steam:				
Cherokee-Denver, Colo., 2 Units	Coal	1957-1968	504	(a)
Comanche-Pueblo, Colo.				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(b)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83	(c)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	237	(d)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505	
Valmont-Boulder, Colo., 1 Unit	Coal	1964	184	
Zuni-Denver, Colo., 1 Unit	Coal	1948-1954	59	
Combustion Turbine:				
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264	
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969	
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	172	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
Wind:				
Ponnequin-Weld County, Colo., 37 Units	Wind	1999-2001	25	(e)
		Total	4,978	

(a) Cherokee Unit 2 was taken out of service in October 2011. Cherokee Unit 1 was taken out of service in May 2012.

(b) Based on PSCo's ownership interest of 67 percent of Unit 3.

(c) Based on PSCo's ownership interest of 10 percent.

(d) Based on PSCo's ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

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

SPS

Station, Location and Unit	Fuel	Installed	Summer 2013 Net Dependable Capability (MW)	
Steam:				
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018	
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067	
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254	
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486	
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112	
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457	
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	411	
Combustion Turbine:				
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	10	
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	212	
Jones-Lubbock, Texas, 2 Units	Natural Gas	2011-2013	339	(a)
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61	
		Total	4,427	

(a) Construction of Jones Unit 3 was completed in 2011 and Jones Unit 4 was completed in May 2013.

Table of Contents

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2013:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	6,392	1,152	2,157	6,806
230 KV	1,802	—	12,153	9,310
161 KV	353	1,572	—	—
138 KV	—	—	92	—
115 KV	7,552	1,739	4,893	12,380
Less than 115 KV	83,469	32,204	74,610	22,782

Electric utility transmission and distribution substations at Dec. 31, 2013:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	351	203	230	429

Natural gas utility mains at Dec. 31, 2013:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	137	—	2,252	11
Distribution	9,855	2,295	21,718	—

Item 3 — Legal Proceedings

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

Additional Information

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

Item 4 — Mine Safety Disclosures

None.

Table of Contents

PART II

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

Quarterly Stock Data

Xcel Energy Inc.’s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The number of common shareholders of record as of Dec. 31, 2013 was approximately 70,548. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2013 and 2012 and the dividends declared per share during those quarters.

2013	High	Low	Dividends
First quarter	$29.74	$26.77	$0.2700
Second quarter	31.79	27.38	0.2800
Third quarter	30.41	26.90	0.2800
Fourth quarter	29.40	27.14	0.2800
2012	High	Low	Dividends
First quarter	$27.93	$25.92	$0.2600
Second quarter	29.12	25.89	0.2700
Third quarter	29.92	27.25	0.2700
Fourth quarter	28.34	25.84	0.2700

Xcel Energy Inc.’s Articles of Incorporation place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there was no preferred stock outstanding at any time during the year ended Dec. 31, 2013, the restrictions did not place any effective limit on Xcel Energy Inc.’s ability to pay dividends. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.’s dividend policy.

The following compares our cumulative TSR on common stock with the cumulative total return of the EEI Investor-Owned Electrics Index and the Standard & Poor’s 500 Composite Stock Price Index over the last five fiscal years (assuming a $100 investment on Dec. 31, 2008, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 49 companies and is a broad measure of industry performance.

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

* $100 invested on Dec. 31, 2008 in stock and index — including reinvestment of dividends. Fiscal years ending Dec. 31.

Table of Contents

	2008	2009	2010	2011	2012	2013
Xcel Energy Inc.	$100	$120	$140	$171	$172	$187
EEI Investor-Owned Electrics	100	111	118	142	145	164
S&P 500	100	126	146	149	172	228

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the year ended Dec. 31, 2013:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2013 — Jan. 31, 2013 [a]	18,175	$27.43	—	—
Feb. 1, 2013 — Dec. 31, 2013	—	—	—	—
Total	18,175		—	—

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

Item 6 — Selected Financial Data

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2013	2012	2011	2010	2009
Operating revenues	$10,915	$10,128	$10,655	$10,311	$9,644
Operating expenses	9,067	8,306	8,873	8,691	8,176
Net income	948	905	841	756	681
Earnings available to common shareholders	948	905	834	752	677
Weighted average common shares outstanding:					
Basic	496,073	487,899	485,039	462,052	456,433
Diluted	496,532	488,434	485,615	463,391	457,139
Earnings per share:					
Basic	$1.91	$1.86	$1.72	$1.63	$1.48
Diluted	1.91	1.85	1.72	1.62	1.48
Dividends declared per common share	1.11	1.07	1.03	1.00	0.97
Total assets	33,907	31,141	29,497	27,388	25,306
Long-term debt [a]	10,911	10,144	8,849	9,263	7,889
Book value per share	19.21	18.19	17.44	16.76	15.92
Return on average common equity	10.3 %	10.4 %	10.1 %	9.8 %	9.5 %
Ratio of earnings to fixed charges [b]	3.1	2.8	2.8	2.7	2.5

Non-GAAP:					
Ongoing earnings [c]	$968	$888	$841	$756	$690

[a] Includes capital lease obligations.
[b] See Exhibit 12.01.
[c] See Item 7 for a reconciliation of ongoing earnings to GAAP earnings.

Table of Contents

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

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. In 2013, Xcel Energy’s operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

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

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2014 EPS guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project, “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto.

Management’s Strategic Plans

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

- Driving operational excellence;
- Providing options and solutions to customers;
- Investing for the future; and
- Enhancing engagement with employees, customers, shareholders, communities and policy makers.

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

Table of Contents

Driving operational excellence

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

Providing options and solutions to customers

Adapting to a changing environment is critical to our success. Our customers expect to be offered choices and we are committed to providing options and solutions that are fair and satisfy their needs. Environmental leadership is a core priority and is designed to meet customer and policy maker expectations for clean energy at a competitive price while creating shareholder value. We will continue to offer and expand our production of renewable energy, including wind and solar alternatives, and further develop DSM, conservation and renewable programs.

Investing for the future

Sound investments today are necessary for tomorrow's success. From 2014 through 2018, we anticipate investing approximately $14.1 billion in our utility businesses, which will grow rate base at a compounded average annual rate of approximately 5.4 percent. Our capital investment plan is primarily intended to take advantage of opportunities to grow the business, refresh our infrastructure, reduce emissions and improve reliability. Xcel Energy has a proven record for making sound investments, including proactive and forward-looking decisions to balance its generation portfolio and expand alternative energy production. Our customers, stakeholders and the environment are currently benefiting from these decisions and will continue to do so in the future. Organic growth will remain a priority, but ventures such as transmission related projects outside our established footprint are also being considered.

Enhancing engagement with employees, customers, shareholders, communities and policy makers

Engagement starts with our employees and creating a productive place to work. Providing the right tools and opportunities to our employees is important not only for their future development, but the future of Xcel Energy. Communicating with customers, shareholders, communities and policymakers is also crucial to enhancing our business relationships and overall engagement. Maintaining a constructive regulatory environment is a key part of our overall strategy. We plan to further improve the regulatory compact by proposing additional rate mitigation methodologies, rider mechanisms and continuing to negotiate multi-year rate agreements.

Provide an attractive total return

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

- Deliver long-term annual EPS growth of four percent to six percent, based on a normalized 2013 EPS of $1.90 per share;
- Deliver annual dividend increases of four percent to six percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

We have successfully achieved our prior financial objectives and believe we are positioned to continue to achieve our value proposition. Our ongoing earnings have grown approximately 6.8 percent and our dividend has grown approximately 3.4 percent annually since 2005. In addition, our current senior unsecured debt credit ratings for Xcel Energy and it utility subsidiaries are in the BBB+ to A range.

Financial Review

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

Table of Contents

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

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy and subsidiaries:

Diluted Earnings (Loss) Per Share	2013	2012	2011
PSCo	$0.91	$0.90	$0.82
NSP-Minnesota	0.79	0.70	0.73
SPS	0.23	0.22	0.18
NSP-Wisconsin	0.12	0.10	0.10
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.04
Regulated utility	2.09	1.96	1.87
Xcel Energy Inc. and other costs	(0.14)	(0.14)	(0.15)
Ongoing diluted earnings per share	1.95	1.82	1.72
SPS 2004 FERC complaint case orders	(0.04)	—	—
Prescription drug tax benefit	—	0.03	—
GAAP diluted earnings per share	$1.91	$1.85	$1.72

Ongoing earnings exclude adjustments for certain items. For 2013, the adjustment is related to the SPS 2004 FERC complaint case orders. For 2012, the adjustment is related to the Patient Protection and Affordable Care Act. See below under Adjustments to GAAP Earnings and Note 12 and Note 6 to the consolidated financial statements for further discussion, respectively, for the 2013 and 2012 adjustments.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

2013 Adjustment to GAAP Earnings

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

2012 Adjustment to GAAP Earnings

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

Table of Contents

Earnings Adjusted for Certain Items (Ongoing EPS)

2013 Comparison with 2012

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

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

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

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

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

2012 Comparison with 2011

Xcel Energy — Overall, ongoing earnings increased $0.10 per share for 2012. Ongoing earnings increased largely due to increases in electric margins driven by the conclusion of various rate cases, which reflect our continued investment in our utility business and a lower ETR. Partially offsetting these positive factors were warmer than normal winter weather, increases in depreciation expense, O&M expenses and property taxes.

PSCo — PSCo's ongoing earnings increased $0.08 per share for 2012. The increase is primarily due to an electric rate increase, effective May 2012, and the impact of warmer summer weather. The increase was partially offset by decreased wholesale revenue due to the expiration of a long-term power sales agreement with Black Hills Corp, higher depreciation expense and O&M expenses.

NSP-Minnesota — NSP-Minnesota's 2012 ongoing earnings decreased $0.03 per share. The decrease is primarily due to the unfavorable impact of warmer than normal winter weather during the first quarter, electric sales decline and higher property taxes, O&M expenses and depreciation expense. These decreases were partially offset by the 2012 rate increase and a lower ETR.

SPS — SPS' ongoing earnings increased $0.04 per share for 2012. The increase is the result of rate increases in New Mexico and Texas, effective January 2012, partially offset by the impact of milder weather during the second half of the year, higher depreciation expense and property taxes.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for 2012. Ongoing earnings were positively impacted by rate increases, effective January 2012, offset by higher O&M expenses.

Table of Contents

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2013 EPS compared with the same period in 2012. See further discussion below.

Diluted Earnings (Loss) Per Share	Dec. 31
2012 GAAP diluted earnings per share	$1.85
Prescription drug tax benefit	(0.03)
2012 ongoing diluted earnings per share	1.82
Components of change — 2013 vs. 2012	
Higher electric margins (excludes impact of SPS 2004 FERC complaint case orders)	0.18
Higher natural gas margins	0.08
Higher AFUDC — equity	0.05
Lower interest charges (excludes impact of SPS 2004 FERC complaint case orders)	0.04
Gain on sale of transmission assets (included in O&M expenses)	0.02
Higher O&M expenses (excludes gain on sale of transmission assets)	(0.14)
Higher depreciation and amortization	(0.06)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Higher taxes (other than income taxes)	(0.01)
2013 ongoing diluted earnings per share	1.95
SPS 2004 FERC complaint case orders	(0.04)
2013 GAAP diluted earnings per share	$1.91

Diluted Earnings (Loss) Per Share	Dec. 31
2011 GAAP and ongoing diluted earnings per share	$1.72
Components of change — 2012 vs. 2011	
Higher electric margins	0.15
Lower ETR	0.04
Lower conservation and DSM expenses (generally offset in revenues)	0.03
Higher AFUDC — equity	0.02
Higher natural gas margins	0.01
Higher O&M expenses	(0.05)
Higher depreciation and amortization	(0.04)
Higher taxes (other than income taxes)	(0.04)
Higher interest charges	(0.01)
Other, net (including interest and premium on redemption of preferred stock)	(0.01)
2012 ongoing diluted earnings per share	1.82
Prescription drug tax benefit	0.03
2012 GAAP diluted earnings per share	$1.85

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

ROE - 2013	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2013 ongoing ROE	9.66 %	9.24 %	9.03 %	10.61 %	10.50 %
SPS 2004 FERC complaint case orders	—	—	(1.54)	—	(0.22)
2013 GAAP ROE	9.66 %	9.24 %	7.49 %	10.61 %	10.28 %

ROE - 2012	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2012 ongoing ROE	9.92 %	8.77 %	9.44 %	9.62 %	10.24 %
Prescription drug tax benefit	0.38	—	—	—	0.19

2012 GAAP ROE	10.30 %	8.77 %	9.44 %	9.62 %	10.43 %

Table of Contents

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

(Millions of Dollars)	2013	2012	2011
Ongoing earnings	$968.4	$888.3	$840.7
SPS 2004 FERC complaint case orders (2013), prescription drug tax benefit (2012) and COLI settlement (2011)	(20.2)	16.9	0.5
GAAP earnings	$948.2	$905.2	$841.2

Diluted Earnings (Loss) Per Share	2013	2012	2011
Ongoing diluted earnings per share [(a)]	$1.95	$1.82	$1.72
SPS 2004 FERC complaint case orders (2013), prescription drug tax benefit (2012) and COLI settlement (2011)	(0.04)	0.03	—
GAAP diluted earnings per share [(a)]	$1.91	$1.85	$1.72

(a) Includes the dividend requirements on preferred stock in 2011.

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

(Millions of Dollars)	2013	2012	2011
GAAP income (loss) by segment			
Regulated electric income	$850.7	$851.9	$789.0
Regulated natural gas income	123.7	98.1	101.8
Other income [(a)]	44.6	22.1	17.9
Xcel Energy Inc. and other costs [(a)]	(70.8)	(66.9)	(67.5)
Total net income	$948.2	$905.2	$841.2

Contributions to Diluted Earnings (Loss) Per Share	2013	2012	2011
GAAP earnings (loss) by segment			
Regulated electric	$1.71	$1.74	$1.62
Regulated natural gas	0.25	0.20	0.21
Other [(a)]	0.09	0.05	0.04
Xcel Energy Inc. and other costs [(a)] [(b)]	(0.14)	(0.14)	(0.15)
Total diluted earnings per share [(b)]	$1.91	$1.85	$1.72

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

(b) Includes the dividend requirements on preferred stock (2011).

Statement of Income Analysis

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

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

Table of Contents

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

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

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

	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2011 vs. Normal	2012 vs. 2011
HDD	6.5 %	(15.9)%	25.8 %	(1.0)%	(14.8)%
CDD	24.7	46.1	(13.6)	38.1	5.7
THI	21.8	36.1	(9.7)	37.9	(0.2)

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

	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2011 vs. Normal	2012 vs. 2011
Retail electric	$0.088	$0.081	$0.007	$0.080	$0.001
Firm natural gas	0.021	(0.033)	0.054	0.002	(0.035)
Total	$0.109	$0.048	$0.061	$0.082	$(0.034)

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

	Dec. 31, 2013		Dec. 31, 2013 (Without 2012 Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	1.1 %	0.2 %	1.4 %	0.5 %
Electric commercial and industrial	—	0.1	0.3	0.4
Total retail electric sales	0.3	0.1	0.6	0.4
Firm natural gas sales [(a)]	21.3	3.3	21.9	3.8

	Dec. 31, 2012		Dec. 31, 2012 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(1.0)%	(0.1)%	(1.2)%	(0.4)%
Electric commercial and industrial	0.1	—	(0.2)	(0.2)
Total retail electric sales	(0.3)	—	(0.5)	(0.3)
Firm natural gas sales [(a)]	(10.6)	(0.3)	(11.0)	(0.8)

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

Weather-normalized sales for 2014 are projected to increase by approximately 0.5 percent for retail electric customers and to decline by approximately 0.0 percent to 2.0 percent for retail firm natural gas customers.

Table of Contents

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 little impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2013	2012	2011
Electric revenues	$9,034	$8,517	$8,767
Electric fuel and purchased power	(4,019)	(3,624)	(3,992)
Electric margin	$5,015	$4,893	$4,775

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

Electric Revenues

(Millions of Dollars)	2013 vs. 2012
Fuel and purchased power cost recovery	$360
Retail rate increases [a]	229
Transmission revenue	68
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Firm wholesale	(36)
Conservation and DSM program incentives	(24)
Trading	(19)
SPS 2004 FERC complaint case orders [b]	(6)
Other, net	(11)
Total increase in ongoing electric revenues	543
SPS 2004 FERC complaint case orders [b]	(26)
Total increase in GAAP electric revenues	$517

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

Electric Margin

(Millions of Dollars)	2013 vs. 2012
Retail rate increases [a]	$229
Transmission revenue, net of costs	36
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Conservation and DSM program incentives	(24)
Firm wholesale	(24)
Trading margin	(12)
SPS 2004 FERC complaint case orders [b]	(6)
Other, net	(33)
Total increase in ongoing electric margin	148
SPS 2004 FERC complaint case orders [b]	(26)
Total increase in GAAP electric margin	$122

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

Table of Contents

(b) As a result of two orders issued by the FERC in August 2013, a pretax charge of approximately $36 million ($32 million in electric revenues, of which $6 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in 2013. See Note 12 to the consolidated financial statements.

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

Electric Revenues

(Millions of Dollars)	2012 vs. 2011
Fuel and purchased power cost recovery	$(394)
Firm wholesale [(a)]	(58)
Retail sales decrease, excluding weather impact	(6)
Conservation and DSM revenue (offset by expenses)	(5)
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, North Dakota, Michigan and Minnesota)	125
Transmission revenue	44
Demand revenue	13
Conservation and DSM incentive	12
Estimated impact of weather	1
Other, net	18
Total decrease in electric revenue	$(250)

2012 Comparison with 2011 — Electric revenues decreased primarily due to lower fuel and purchased power cost recovery, which is offset in operating expense. This decrease was partially offset by the various rate increases across all of the utility subsidiaries.

Electric Margin

(Millions of Dollars)	2012 vs. 2011
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, North Dakota, Michigan and Minnesota)	$125
Demand revenue	13
Transmission revenue, net of costs	13
Conservation and DSM incentive	12
Estimated impact of weather	1
Firm wholesale [(a)]	(48)
Retail sales decrease, excluding weather impact	(6)
Conservation and DSM revenue (offset by expenses)	(5)
Other, net	13
Total increase in electric margin	$118

(a) Decrease is primarily due to the expiration of a long-term wholesale power sales agreement with Black Hills Corp., effective Jan. 1, 2012.

2012 Comparison to 2011 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

Table of Contents

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)	2013	2012	2011
Natural gas revenues	$1,805	$1,537	$1,812
Cost of natural gas sold and transported	(1,083)	(881)	(1,164)
Natural gas margin	$722	$656	$648

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

Natural Gas Revenues

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

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

Natural Gas Margin

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

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

Natural Gas Revenues

(Millions of Dollars)	2012 vs. 2011
Purchased natural gas adjustment clause recovery	$(282)
Estimated impact of weather	(26)
Conservation and DSM revenue (offset by expenses)	(17)
PSIA rider (Colorado), offset by expenses	29
Retail rate increase (Colorado, Wisconsin)	16
Other, net	5

Total decrease in natural gas revenues	$(275)

63

Table of Contents

2012 Comparison to 2011 — Natural gas revenues decreased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2012 vs. 2011
PSIA rider (Colorado) offset by expenses	$29
Retail rate increase (Colorado, Wisconsin)	16
Estimated impact of weather	(26)
Conservation and DSM revenue (offset by expenses)	(17)
Other, net	6
Total increase in natural gas margin	$8

2012 Comparison to 2011 — Natural gas margins increased primarily due to the PSIA rider, which is offset in operating expense.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $97.4 million, or 4.5 percent, for 2013 compared with 2012, and by $35.8 million, or 1.7 percent, for 2012 compared with 2011. The following tables summarize the changes in O&M expenses:

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

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

- Electric and gas distribution expenses were primarily driven by increased maintenance activities due to vegetation management, storms and outages;
- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs;
- Higher employee benefits related primarily to increased pension expense; and
- See Note 12 to the consolidated financial statements for further discussion of the gain on sale of transmission assets.

(Millions of Dollars)	2012 vs. 2011
Employee benefits	$36
Pipeline system integrity costs	20
SmartGridCity	11
Prairie Island EPU	10
Plant generation costs	(17)
Bad debt expense	(10)
Labor and contract labor	(2)
Other, net	(12)
Total increase in O&M expenses	$36

2012 Comparison to 2011 — The increase in O&M expenses for 2012 was largely driven by the following:

- Higher employee benefits are mainly due to increased pension expenses.
- Higher pipeline system integrity costs relate to increased compliance and inspection initiatives, which in Colorado are recovered through the pipeline system integrity rider.

Table of Contents

- See Note 12 to the consolidated financial statements for further discussion of SmartGridCity and Prairie Island EPU.
- Lower plant generation costs are primarily attributable to fewer plant overhauls in 2012.

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $20.9 million, or 7.4 percent, for 2012 compared with 2011. The lower expenses are primarily attributable to lower gas rider rates, as well as the timing of recovery of electric CIP expenses at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Overall, the programs are designed to encourage the operating companies and their retail customers to conserve energy or change energy usage patterns in order to reduce peak demand on the gas or electric system. This, in turn, reduces the need for additional plant capacity, reduces emissions, serves to achieve other environmental goals as well as reduces energy costs to participating customers.

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

Depreciation and amortization increased $35.4 million, or 4.0 percent, for 2012 compared with 2011. The increase is primarily due to a portion of the Monticello EPU going into service in May 2011 at NSP-Minnesota, the Jones Unit 3 going into service in June 2011 at SPS and normal system expansion across Xcel Energy’s service territories.

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

Taxes (other than income taxes) increased $34.1 million, or 9.1 percent, for 2012 compared with 2011. The increases are due to an increase in property taxes primarily in Minnesota. Higher property taxes in Colorado related to the electric retail business are being deferred, based on the multi-year rate settlement approved by the CPUC in May 2012.

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

AFUDC increased $18.8 million for 2012, compared with 2011. The increase is primarily due to the expansion of PSCo’s transmission facilities, additional construction related to the Colorado CACJA and life extension work at the Prairie Island nuclear generating plant.

Interest Charges — Interest charges decreased $26.4 million, or 4.4 percent, for 2013 compared with 2012. The decrease is primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels, $4 million of interest associated with the customer refund at SPS based on the August 2013 FERC orders, $5 million of interest associated with customer refunds in Minnesota for the 2013 electric rate case and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Interest charges increased $10.5 million, or 1.8 percent for 2012 compared with 2011. The increase is due to higher long-term debt levels to fund investment in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense increased $33.8 million for 2013 compared with 2012. The increase in income tax expense was primarily due to higher pretax earnings in 2013, a tax benefit for a carryback in 2012 and for the restoration in 2012 of a portion of the tax benefit associated with federal subsidies for prescription drug plans that was previously written off in 2010. These were partially offset in 2013 by a tax benefit for a carryback claim related to

2013, research and experimentation credits and increased permanent plant-related reductions. The ETR was 33.8 percent for 2013 compared with 33.2 percent for 2012. The higher ETR for 2013 was primarily due to the adjustments referenced above. See Note 6 to the consolidated financial statements for further discussion.

Income tax expense decreased $18.1 million for 2012 compared with 2011. The decrease in income tax expense was primarily due to a tax benefit associated with a carryback and a tax benefit related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. As a result, Xcel Energy recognized tax benefits of approximately $14.9 million for the carryback and $17 million for the tax benefit associated with the federal subsidies. These were partially offset by higher pretax income in 2012. The ETR was 33.2 percent for 2012, compared with 35.8 percent for 2011. The lower ETR for 2012 was primarily due to the adjustments referenced above. The ETR would have been 35.6 percent for 2012 without these tax benefits.

Table of Contents

Premium on Redemption of Preferred Stock — Xcel Energy Inc. redeemed all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions to earnings available to common shareholders for 2011.

Xcel Energy Inc. and Other Results

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

	Contribution to Xcel Energy's Earnings		
(Millions of Dollars)	2013	2012	2011
Xcel Energy Inc. financing costs	$(62.9)	$(71.5)	$(63.8)
Eloigne [(a)]	(0.8)	3.8	(2.9)
Xcel Energy Inc. taxes and other results	(7.1)	0.8	(0.6)
Total Xcel Energy Inc. and other costs	(70.8)	(66.9)	(67.3)
Preferred dividends	—	—	(6.8)
Total Xcel Energy Inc. and other costs, available to common shareholders	$(70.8)	$(66.9)	$(74.1)

	Contribution to Xcel Energy's Earnings per Share		
(Earnings per Share)	2013	2012	2011
Xcel Energy Inc. financing costs	$(0.13)	$(0.15)	$(0.13)
Eloigne [(a)]	—	0.01	(0.01)
Xcel Energy Inc. taxes and other results	(0.01)	—	—
Preferred dividends	—	—	(0.01)
Total Xcel Energy Inc. and other costs	$(0.14)	$(0.14)	$(0.15)

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

Xcel Energy Inc.'s results include interest charges and the EPS impact of preferred dividends, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

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

General Economic Conditions

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

Fuel Supply and Costs

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

Table of Contents

Pension Plan Costs and Assumptions

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

Regulation

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

The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of filing general rate cases and the implementation of final rates. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales, which are affected by overall economic conditions, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings.

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

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

Environmental Matters

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

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

- $275 million in 2013;
- $263 million in 2012; and
- $265 million in 2011.

Table of Contents

Xcel Energy estimates an average annual expense of approximately $320 million from 2014 through 2018 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $517 million in 2013;
- $255 million in 2012; and
- $48 million in 2011.

See Item 7 — Capital Requirements for further discussion.

Xcel Energy's operations are subject to federal and state laws and regulations related to air emissions, water discharges and waste management. These laws and regulations regulate air emissions from various sources, including electrical generating units, and impose certain monitoring and reporting requirements. Such laws and regulations may require Xcel Energy to obtain pre-approval for the construction or modification of certain projects that increase air emissions, obtain and strictly comply with air permits that contain emission and operational limitations, or install or operate pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation plans of MGP sites and various regulations for air emissions and water intake. Actual expenditures could be higher or lower than the estimates presented and the scope and timing of these expenditures cannot be fully determined until any new or revised regulations become final.

In 2011, the EPA issued the CSAPR to address 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. In August 2012, the D.C. Circuit vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated that the EPA must continue administering the CAIR pending adoption of a valid replacement. In December 2013, the U.S. Supreme Court heard oral arguments on the D.C. Circuit's 2012 decision to vacate the CSAPR. A decision is anticipated by June 2014. It is not yet known whether the D.C. Circuit's decision will be upheld, or how the EPA might approach a replacement rule. Therefore, it is not known what requirements may be imposed in the future.

In addition, there are emission controls, known as BART, for industrial facilities releasing emissions that reduce visibility in certain national parks and wilderness areas. Xcel Energy generating facilities in Minnesota and Colorado are subject to BART requirements.

Further, generating facilities throughout the Xcel Energy territory are subject to state and federal mercury reduction requirements.

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

Inflation

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Table of Contents

Regulatory Accounting

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

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

As of Dec. 31, 2013 and 2012, Xcel Energy has recorded regulatory assets of $2.9 billion and $3.1 billion and regulatory liabilities of $1.3 billion and $1.2 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets. However, if the SEC should mandate the use of IFRS and the lack of an accounting standard for rate-regulated entities under IFRS could require us to charge certain regulatory assets and regulatory liabilities to net income or OCI. See Note 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities and Note 12 to the consolidated financial statements for further discussion of rate matters.

Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR. Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our ETR in the future.

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

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted ETR.

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

As disputes with the IRS and state tax authorities are resolved over time, we may adjust our unrecognized tax benefits and interest accruals to the updated estimates needed to satisfy tax and interest obligations for the related issues. These adjustments may increase or decrease earnings. See Note 6 to the consolidated financial statements for further discussion.

Table of Contents

Employee Benefits

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

Pension costs are expected to decrease in 2014 and continue to decline in the following few years. Funding requirements are also expected to decline in 2014 and then be flat in the following years. While investment returns exceeded the assumed levels from 2009 through 2012, investment returns were slightly below the assumed levels in 2013. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects the pension costs recognized for financial reporting purposes will decrease from an expense of $151.8 million in 2013 and $127.1 million in 2012 to an expense of $126.8 million in 2014 and $109.0 million in 2015. The expected decrease in the 2014 expense is due primarily to an increase in the discount rate along with the reduced amortization of prior service costs and other historic loss amounts, including the 2008 market loss. Further, future year expenses are expected to decrease primarily as a result of reductions in loss amortizations and an increase in expected return on assets as a result of increases in assets via planned contributions and the subsequent expected return of current assets.

At Dec. 31, 2013, Xcel Energy set the rate of return on assets used to measure pension costs at 7.05 percent, which is a 17 basis point increase from Dec. 31, 2012. The rate of return used to measure postretirement health care costs is 7.17 percent at Dec. 31, 2013 and is a six basis point increase from Dec. 31, 2012.

Xcel Energy set the discount rates used to value the Dec. 31, 2013 pension and postretirement health care obligations at 4.75 percent and 4.82 percent, which represent a 75 basis point and 72 basis point increase from Dec. 31, 2012, respectively. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration. The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Citigroup Pension Liability Discount Curve and the Citigroup Above Median Curve. At Dec. 31, 2013, these reference points supported the selected rate. In addition to these reference points, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The following are the pension funding contributions, both voluntary and required, made by Xcel Energy for 2011 through 2014:

- In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans;
- In 2013, contributions of $192.4 million were made across four of Xcel Energy's pension plans;
- In 2012, contributions of $198.1 million were made across four of Xcel Energy's pension plans; and

In 2011, contributions of $137.3 million were made across three of Xcel Energy’s pension plans.

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

Table of Contents

If Xcel Energy were to use alternative assumptions at Dec. 31, 2013, a one-percent change would result in the following impact on 2014 pension expense:

	Pension Costs	
(Millions of Dollars)	+1%	-1%
Rate of return	$(25.1)	$25.5
Discount rate	(11.2)	14.1

Effective Jan. 1, 2014, the initial medical trend assumption was decreased from 7.5 percent to 7.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is five years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed $17.6 million, $47.1 million and $49.0 million during 2013, 2012 and 2011, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately $13.3 million during 2014.

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

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

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

Nuclear Decommissioning

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

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The total obligation for nuclear decommissioning currently is expected to be funded 100 percent by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and amounts recorded under current accounting guidance are deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $1,627 million and $1,490 million as of Dec. 31, 2013 and 2012, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. These independent cost studies are based on relevant information available at the time performed. Estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results.

Table of Contents

In November 2012, the MPUC approved NSP-Minnesota's most recent nuclear decommissioning study. The decommissioning study, which covered all expenses over the decommissioning period of the nuclear plants, including decontamination and removal of radioactive material. The estimated future costs were initially determined in nominal amounts (2011 dollars) prior to escalation adjustments, then future periods' costs were escalated using decommissioning-specific cost escalators and finally discounted using risk-free, credit adjusted interest rates.

The MPUC approved the use of a 60-year decommissioning scenario. This resulted in an approved annual accrual of $14.2 million for Minnesota retail customers, to be held in our external escrow fund.

The following key assumptions have a significant effect on these estimates:

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

- Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's 2011 nuclear decommissioning filing assumed current technology and regulations.

- Escalation Rates — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 3.63 percent in calculating the AROs related to nuclear decommissioning for the remaining operational period through the radiological decommissioning period. An escalation rate of 2.63 percent was utilized for the period of operating costs related to interim dry cask storage of spent nuclear fuel and site restoration.

- Discount Rates — Changes in timing or estimated expected cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. The estimated expected cash flows that changed in 2012 due to the change to a 60 year decommissioning assumption resulted in an immaterial revision to the ARO. Discount rates ranging from approximately four and seven percent have been used to calculate the net present value of the expected future cash flows over time.

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

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2013.

Table of Contents

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

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

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

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

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

At Dec. 31, 2013, 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	$9,746	$16,918	$2,516	$1,049	$30,229
NSP-Minnesota	2	(646)	—	—	604	(42)
PSCo	1	318	—	—	—	318
		$9,418	$16,918	$2,516	$1,653	$30,505

	Options					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value

NSP-Minnesota	2	$9	$—	$—	$—	$9

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

Table of Contents

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)	2013	2012
Fair value of commodity trading net contract assets outstanding at Jan. 1	$28,314	$20,424
Contracts realized or settled during the period	(6,665)	(12,185)
Commodity trading contract additions and changes during the period	8,865	20,075
Fair value of commodity trading net contract assets outstanding at Dec. 31	$30,514	$28,314

At Dec. 31, 2013, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.6 million, whereas a 10 percent decrease would increase pretax income by approximately $0.6 million. At Dec. 31, 2012, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.5 million.

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

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

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2013	$0.29	$3.00	$0.41	$1.65	$ <0.01
2012	0.45	3.00	0.36	1.56	0.06

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

In conjunction with the NSP-Minnesota debt issuance in August 2012, NSP-Minnesota settled interest rate hedging instruments with a notional amount of $225 million with cash payments of $45.0 million. In conjunction with the PSCo debt issuance in September 2012, PSCo settled interest rate hedging instruments with a notional amount of $250 million with cash payments of $44.7 million. These losses are classified as a component of accumulated other comprehensive loss on the consolidated balance sheet, net of tax, and are being reclassified to earnings over the term of the hedged interest payments. See Note 4 to the consolidated financial statements for further discussion of long-term borrowings.

At Dec. 31, 2013 and 2012, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $8.3 million and $6.0 million, respectively. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2013, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have an impact on earnings.

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

Table of Contents

At Dec. 31, 2013, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $15.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2.6 million. At Dec. 31, 2012, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $11.6 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $12.6 million.

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

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2013. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2013.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 3.0 percent and 28.7 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2013.

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 $48.3 million and $10.0 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2013.

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. Level 3 commodity derivative assets and liabilities included $3.4 million and zero of estimated fair values, respectively, for forwards held at Dec. 31, 2013. There were no Level 3 options held at Dec. 31, 2013.

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 $120.1 million in the nuclear decommissioning fund at Dec. 31, 2013 (approximately 6.9 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.

Table of Contents

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2013	2012	2011
Net cash provided by operating activities	$2,584	$2,005	$2,406

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

Net cash provided by operating activities decreased by $401 million for 2012 as compared to 2011. The decrease was the result of changes in working capital due to the timing of payments and receipts, higher pension contributions, interest rate swap settlements and the effect of income taxes paid in 2012 compared to a refund received in 2011, partially offset by higher net income.

(Millions of Dollars)	2013	2012	2011
Net cash used in investing activities	$(3,213)	$(2,333)	$(2,248)

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

Net cash used in investing activities increased by $85 million for 2012 as compared to 2011. The increase was the result of higher capital expenditures, partially offset by the change in restricted cash due to customer refunds associated with the nuclear waste disposal settlement with the DOE and insurance proceeds related to Sherco Unit 3 received in 2012.

(Millions of Dollars)	2013	2012	2011
Net cash provided by (used in) financing activities	$654	$350	$(205)

Net cash provided by financing activities increased by $304 million for 2013 as compared to 2012. The increase was primarily due to the issuance of more common stock during 2013, lower repayments of previously existing long-term debt, which was partially offset by reductions in long-term and short-term borrowing.

Net cash provided by financing activities increased by $555 million for 2012 as compared to 2011. The increase was primarily due to higher proceeds from short-term borrowings and the issuance of long-term debt, partially offset by repayments of previously existing long-term debt, repurchases of common stock and higher dividend payments.

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

Capital Requirements

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

Table of Contents

Capital Expenditures — The current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2014 through 2018 are shown in the table below.

	Actual	Forecast				
(Millions of Dollars)	2013	2014	2015	2016	2017	2018
By Subsidiary						
NSP-Minnesota	$1,505	$1,090	$1,620	$955	$885	$805
PSCo	1,074	985	845	795	770	815
SPS	555	525	520	610	770	790
NSP-Wisconsin	217	290	210	265	275	275
WYCO	8	—	—	—	—	—
Total capital expenditures	$3,359	$2,890	$3,195	$2,625	$2,700	$2,685
By Function	2013	2014	2015	2016	2017	2018
Electric transmission	$1,073	$950	$770	$790	$945	$1,035
Electric generation	1,116	715	1,235	560	550	470
Electric distribution	551	510	560	595	605	610
Natural gas	316	365	340	345	300	320
Nuclear fuel	90	140	100	135	135	75
Other	213	210	190	200	165	175
Total capital expenditures	$3,359	$2,890	$3,195	$2,625	$2,700	$2,685
By Project	2013	2014	2015	2016	2017	2018
Other major transmission projects	$335	$370	$265	$330	$420	$385
CapX2020 transmission project	330	255	125	5	—	—
PSCo CACJA	350	250	85	10	—	—
Natural gas pipeline replacement	115	160	180	145	125	125
Nuclear fuel	90	140	100	135	135	75
NSP-Minnesota wind projects	—	35	610	—	—	—
Southwest infrastructure expansion	—	5	70	170	290	385
NSP-Minnesota Black Dog	—	5	50	40	5	—
Other capital expenditures	2,139	1,670	1,710	1,790	1,725	1,715
Total capital expenditures	$3,359	$2,890	$3,195	$2,625	$2,700	$2,685

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities.

Table of Contents

Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2013. See the statements of capitalization and additional discussion in Notes 4 and 13 to the consolidated financial statements.

	Payments Due by Period				
(Thousands of Dollars)	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Long-term debt, principal and interest payments [(a)]	$18,532,746	$758,294	$1,846,741	$2,438,796	$13,488,915
Capital lease obligations	371,697	17,966	34,896	29,686	289,149
Operating leases [(b)(c)]	3,028,807	240,669	452,213	420,423	1,915,502
Unconditional purchase obligations [(d)]	12,087,474	2,217,694	3,103,409	1,776,893	4,989,478
Other long-term obligations, including current portion [(e)]	218,718	55,416	85,089	62,743	15,470
Payments to vendors in process	28,955	28,955	—	—	—
Short-term debt	759,000	759,000	—	—	—
Total contractual cash obligations [(f)(g)(h)]	$35,027,397	$4,077,994	$5,522,348	$4,728,541	$20,698,514

(a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2013, and outstanding principal for each investment with the terms ending at each instrument's maturity.

(b) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2013, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $73.4 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(c) Included in operating lease payments are $214.2 million, $404.4 million, $387.1 million and $1.8 billion, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

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

(e) Other long-term obligations relate primarily to amounts associated with technology agreements as well as uncertain tax positions.

(f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately $3.1 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table.

(g) In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

(h) Xcel Energy expects to contribute approximately $13.3 million to the postretirement health care plans during 2014. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. Xcel Energy's general objective is to continue to grow annual EPS four percent to six percent and to grow the annual dividend four percent to six percent. On Feb. 19, 2014, Xcel Energy announced dividends of $0.30

per share. Xcel Energy’s dividend policy balances:

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

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

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

Table of Contents

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the CFTC and the SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the de minimis exemption level and will not subject an entity to registering as a swap dealer. Xcel Energy's current and projected swap activity is well below this de minimis level. The CFTC has set an $800 million de minimis volume exemption for swaps with "Utility Special Entities," defined by the CFTC as primarily entities owning or operating electric or natural gas facilities and government entities, after which the entity would have to register as a swap dealer. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy has completed its review of the additional reporting obligations for "trade options," which are physical electric and gas contracts that contain embedded volumetric and/or price optionality. At this time, none of the contracts reviewed qualify as a "trade option." However, this determination is subject to change as additional Dodd-Frank Act rules continue to be finalized and implemented and subsequent transactions are executed. Xcel Energy is currently meeting all other reporting requirements.

SPP FTR Margining Requirements — The SPP conducted its initial auction for FTRs in 2013. The full process for transmission owners involves the receipt of Auction Revenue Rights (ARRs), and if elected by the transmission owner, conversion of those ARRs to firm FTRs. At Dec. 31, 2013, SPS had a $26 million letter of credit posted as collateral for its SPP FTRs. In early January 2014, this letter of credit was reduced to $17 million.

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

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

(Millions of Dollars)	Dec. 31, 2013	Dec. 31, 2012
Fair value of pension assets	$3,010	$2,944
Projected pension obligation [(a)]	3,441	3,640
Funded status	$(431)	$(696)

[(a)] Excludes nonqualified plan of $37 million and $39 million at Dec. 31, 2013 and 2012, respectively.

Pension Assumptions	2013	2012
Discount rate	4.75 %	4.00 %
Expected long-term rate of return	7.05	6.88

Table of Contents

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Dec. 31, 2013, approximately $21.7 million of cash was held in these accounts.

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

- $800 million for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $300 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2013	
Borrowing limit	$2,450	
Amount outstanding at period end	759	
Average amount outstanding	515	
Maximum amount outstanding	759	
Weighted average interest rate, computed on a daily basis	0.29	%
Weighted average interest rate at end of period	0.25	

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2013		Twelve Months Ended Dec. 31, 2012		Twelve Months Ended Dec. 31, 2011	
Borrowing limit	$2,450		$2,450		$2,450	
Amount outstanding at period end	759		602		219	
Average amount outstanding	481		403		430	
Maximum amount outstanding	1,160		634		824	
Weighted average interest rate, computed on a daily basis	0.31	%	0.35	%	0.36	%
Weighted average interest rate at end of period	0.25		0.36		0.40	

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.45 billion and each credit facility terminates in July 2017.

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

Table of Contents

As of Feb. 18, 2014, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$800.0	$582.0	$218.0	$0.2	$218.2
PSCo	700.0	6.4	693.6	0.5	694.1
NSP-Minnesota	500.0	305.9	194.1	0.4	194.5
SPS	300.0	102.0	198.0	0.9	198.9
NSP-Wisconsin	150.0	48.0	102.0	0.5	102.5
Total	$2,450.0	$1,044.3	$1,405.7	$2.5	$1,408.2

(a) These credit facilities expire in July 2017.

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

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

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

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2013 and 2012, Xcel Energy Inc. had approximately 498 million shares and 488 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of seven million shares of $100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2013 and 2012. Xcel Energy Inc. and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy Inc. has an effective automatic shelf registration statement filed in August 2012, which does not contain a limit on issuance capacity. However, Xcel Energy Inc.'s ability to issue securities is limited by authority granted by the Board of Directors, which currently authorizes the issuance of up to an additional $900 million of debt and common equity securities.
- NSP-Minnesota has an automatic shelf registration statement filed in December 2013, which does not contain a limit on issuance capacity. However, NSP-Minnesota's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $600 million of debt securities.
- NSP-Wisconsin has $200 million of debt securities remaining under its currently effective shelf registration statement, which was filed in December 2013.
- PSCo has an automatic shelf registration statement filed in October 2013, which does not contain a limit on issuance capacity. However, PSCo's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $1.0 billion of debt securities.
- SPS has $300 million of debt securities remaining under its currently effective shelf registration statement, which was filed in April 2013.

Table of Contents

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

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

- PSCo issued $250 million of 2.50 percent first mortgage bonds due March 15, 2023 and $250 million of 3.95 percent first mortgage bonds due March 15, 2043. PSCo used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term borrowings incurred to fund daily operational needs;
- Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016. Xcel Energy Inc. used a portion of the proceeds from the sale of the notes to repay short-term borrowings and for other general corporate purposes;
- NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023. NSP-Minnesota used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term borrowings and for other general corporate purposes; and
- SPS issued $100 million of 4.50 percent first mortgage bonds due Aug. 15, 2041. SPS used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term borrowings incurred to fund daily operational needs. Including the $300 million of this series previously issued in August 2011 and June 2012, total principal outstanding for this series is $400 million.

In March 2013, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $400 million of its common stock through an at-the-market offering program. No shares of common stock have been issued through this program since April 2013. As of Dec. 31, 2013, Xcel Energy Inc. sold 7.7 million shares of common stock with net proceeds of $223 million.

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

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

During the first half of 2014, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- PSCo may issue approximately $300 million of first mortgage bonds;
- NSP-Minnesota may issue approximately $300 million of first mortgage bonds;
- SPS may issue approximately $150 million of first mortgage bonds; and
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds.

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

Credit Ratings — Access to reasonably priced capital markets is dependent in part on credit and ratings. On Feb. 14, 2013, Standard and Poor’s upgraded SPS senior secured debt by one notch. On Nov. 14, 2013, Fitch Ratings upgraded both PSCo senior unsecured debt and PSCo senior secured debt by one notch.

On Jan. 31, 2014, Moody’s upgraded each of the following ratings by one notch:

- Xcel Energy Inc. senior unsecured debt;

- NSP-Minnesota senior unsecured debt;
- NSP-Minnesota commercial paper;
- NSP-Wisconsin senior unsecured debt;
- NSP-Wisconsin commercial paper;
- PSCo senior unsecured debt; and
- SPS senior unsecured debt.

Table of Contents

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy’s 2014 ongoing earnings guidance is $1.90 to $2.05 per share. Key assumptions related to 2014 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales are projected to increase by approximately 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline by approximately 0.0 percent to 2.0 percent.
- Capital rider revenue is projected to increase by $50 million to $60 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $30 million to $40 million over 2013 levels, reflecting the proposed acceleration of the depreciation reserve as part of NSP-Minnesota’s moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $50 million to $55 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $0 to $10 million from 2013 levels.
- AFUDC — equity is projected to increase approximately $5 million to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 507 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

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

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on a normalized 2013 EPS of $1.90 per share;
- Deliver annual dividend increases of 4 percent to 6 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

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

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

Table of Contents

Management Report on Internal Controls Over Financial Reporting

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

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

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2013. 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 (1992). Based on our assessment, we believe that, as of Dec. 31, 2013, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent auditors have issued an audit report on the Xcel Energy Inc.'s internal control over financial reporting. Their report appears herein.

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Chairman, President and Chief Executive Officer
Feb. 21, 2014

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
Feb. 21, 2014

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. and subsidiaries (the “Company”) as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholders’ equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control-Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2014 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 21, 2014

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2013 of the Company and our report dated February 21, 2014 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 21, 2014

Table of Contents

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

	Year Ended Dec. 31		
	2013	2012	2011
Operating revenues			
Electric	$9,034,045	$8,517,296	$8,766,593
Natural gas	1,804,679	1,537,374	1,811,926
Other	76,198	73,553	76,251
Total operating revenues	10,914,922	10,128,223	10,654,770
Operating expenses			
Electric fuel and purchased power	4,018,672	3,623,935	3,991,786
Cost of natural gas sold and transported	1,082,751	880,939	1,163,890
Cost of sales — other	33,323	29,067	30,391
Operating and maintenance expenses	2,273,532	2,176,095	2,140,289
Conservation and demand side management program expenses	260,726	260,527	281,378
Depreciation and amortization	977,863	926,053	890,619
Taxes (other than income taxes)	420,500	408,924	374,815
Total operating expenses	9,067,367	8,305,540	8,873,168
Operating income	1,847,555	1,822,683	1,781,602
Other income, net	2,972	6,175	9,255
Equity earnings of unconsolidated subsidiaries	30,020	29,971	30,527
Allowance for funds used during construction — equity	87,683	62,840	51,223
Interest charges and financing costs			
Interest charges — includes other financing costs of $30,135, $24,087 and $24,019, respectively	575,199	601,552	591,300
Allowance for funds used during construction — debt	(39,179)	(35,315)	(28,181)
Total interest charges and financing costs	536,020	566,237	563,119
Income before income taxes	1,432,210	1,355,432	1,309,488
Income taxes	483,976	450,203	468,316
Net income	948,234	905,229	841,172
Dividend requirements on preferred stock	—	—	3,534
Premium on redemption of preferred stock	—	—	3,260
Earnings available to common shareholders	$948,234	$905,229	$834,378
Weighted average common shares outstanding:			
Basic	496,073	487,899	485,039
Diluted	496,532	488,434	485,615
Earnings per average common share:			
Basic	$1.91	$1.86	$1.72
Diluted	1.91	1.85	1.72

Cash dividends declared per common share	$1.11	$1.07	$1.03

See Notes to Consolidated Financial Statements

Table of Contents

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

	Year Ended Dec. 31		
	2013	2012	2011
Net income	$948,234	$905,229	$841,172
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical benefit gains (losses) arising during the period, net of tax of $1,746, $(4,898) and $(4,442), respectively	1,408	(7,005)	(6,367)
Amortization of losses included in net periodic benefit cost, net of tax of $4,151, $2,567 and $2,195, respectively	3,306	3,694	3,162
	4,714	(3,311)	(3,205)
Derivative instruments:			
Net fair value increase (decrease), net of tax of $17, $(12,593) and $(25,086), respectively	12	(19,200)	(38,292)
Reclassification of losses to net income, net of tax of $2,541, $2,687 and $598, respectively	1,476	3,697	648
	1,488	(15,503)	(37,644)
Marketable securities:			
Net fair value increase (decrease), net of tax of $117, $135 and $(63), respectively	176	196	(93)
Other comprehensive income (loss)	6,378	(18,618)	(40,942)
Comprehensive income	$954,612	$886,611	$800,230

See Notes to Consolidated Financial Statements

Table of Contents

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

	Year Ended Dec. 31		
	2013	2012	2011
Operating activities			
Net income	$948,234	$905,229	$841,172
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,001,843	943,702	908,853
Conservation and demand side management program amortization	6,531	7,258	9,816
Nuclear fuel amortization	98,089	102,651	100,902
Deferred income taxes	515,062	508,094	466,567
Amortization of investment tax credits	(5,753)	(6,610)	(6,194)
Allowance for equity funds used during construction	(87,683)	(62,840)	(51,223)
Equity earnings of unconsolidated subsidiaries	(30,020)	(29,971)	(30,527)
Dividends from unconsolidated subsidiaries	36,416	33,470	34,034
Provision for bad debts	37,627	33,808	44,521
Share-based compensation expense	24,613	26,970	45,006
Gain on sale of transmission assets	(13,661)	—	—
Prairie Island EPU and SmartGridCity	—	20,766	—
Net realized and unrealized hedging and derivative transactions	(4,704)	(85,308)	9,966
Changes in operating assets and liabilities:			
Accounts receivable	(108,911)	(197,236)	(79,701)
Accrued unbilled revenues	(23,867)	25,377	19,951
Inventories	(43,588)	82,658	(57,432)
Other current assets	(18,071)	(30,737)	62,660
Accounts payable	132,441	(100,327)	13,748
Net regulatory assets and liabilities	141,325	5,866	149,282
Other current liabilities	126,555	42,914	112,353
Pension and other employee benefit obligations	(156,369)	(183,922)	(150,717)
Change in other noncurrent assets	(9,998)	(33,151)	24,069
Change in other noncurrent liabilities	17,925	(3,905)	(61,584)
Net cash provided by operating activities	2,584,036	2,004,756	2,405,522
Investing activities			
Utility capital/construction expenditures	(3,395,325)	(2,570,209)	(2,205,567)
Proceeds from sale of transmission assets	37,118	—	—
Proceeds from insurance recoveries	90,000	97,835	—
Allowance for equity funds used during construction	87,683	62,840	51,223
Merricourt refund	—	—	101,261
Merricourt deposit	—	—	(90,833)
Purchases of investments in external decommissioning fund	(1,481,881)	(1,102,025)	(2,098,642)
Proceeds from the sale of investments in external decommissioning fund	1,461,291	1,087,076	2,098,642
Investment in WYCO Development LLC	(7,504)	(980)	(2,446)
Change in restricted cash	—	95,287	(95,287)
Other, net	(4,766)	(2,766)	(6,152)
Net cash used in investing activities	(3,213,384)	(2,332,942)	(2,247,801)
Financing activities			

Proceeds from (repayments of) short-term borrowings, net	157,000	383,000	(247,400)
Proceeds from issuance of long-term debt	1,431,895	1,790,131	688,598
Repayments of long-term debt, including reacquisition premiums	(652,451)	(1,302,763)	(105,623)
Proceeds from issuance of common stock	231,767	8,050	38,691
Repurchase of common stock	—	(18,529)	—
Purchase of common stock for settlement of equity awards	—	(23,307)	—
Redemption of preferred stock	—	—	(104,980)
Dividends paid	(514,042)	(486,757)	(474,760)
Net cash provided by (used in) financing activities	654,169	349,825	(205,474)
Net change in cash and cash equivalents	24,821	21,639	(47,753)
Cash and cash equivalents at beginning of period	82,323	60,684	108,437
Cash and cash equivalents at end of period	$107,144	$82,323	$60,684
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$(514,911)	$(563,517)	$(531,148)
Cash received (paid) for income taxes, net	17,188	(9,570)	55,764
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	$452,453	$289,802	$137,558
Issuance of common stock for reinvested dividends and 401(k) plans	56,950	67,723	71,715

See Notes to Consolidated Financial Statements

Table of Contents

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

	Dec. 31 2013	2012
Assets		
Current assets		
Cash and cash equivalents	$107,144	$82,323
Accounts receivable, net	744,160	718,046
Accrued unbilled revenues	687,230	663,363
Inventories	576,538	535,574
Regulatory assets	417,801	352,977
Derivative instruments	91,707	69,013
Deferred income taxes	341,202	32,528
Prepayments and other	252,258	171,315
Total current assets	3,218,040	2,625,139
Property, plant and equipment, net	26,122,159	23,809,348
Other assets		
Nuclear decommissioning fund and other investments	1,755,990	1,617,865
Regulatory assets	2,509,218	2,762,029
Derivative instruments	84,842	126,297
Other	217,241	200,008
Total other assets	4,567,291	4,706,199
Total assets	$33,907,490	$31,140,686
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$280,763	$258,155
Short-term debt	759,000	602,000
Accounts payable	1,261,238	959,093
Regulatory liabilities	274,769	168,858
Taxes accrued	378,766	334,441
Accrued interest	159,372	162,494
Dividends payable	139,432	131,748
Derivative instruments	23,382	32,482
Other	377,776	287,802
Total current liabilities	3,654,498	2,937,073
Deferred credits and other liabilities		
Deferred income taxes	5,331,046	4,434,909
Deferred investment tax credits	79,239	82,761
Regulatory liabilities	1,059,395	1,059,939
Asset retirement obligations	1,815,390	1,719,796
Derivative instruments	209,224	242,866
Customer advances	275,555	252,888
Pension and employee benefit obligations	769,222	1,163,265

Other	237,217	229,207
Total deferred credits and other liabilities	9,776,288	9,185,631
Commitments and contingencies		
Capitalization		
Long-term debt	10,910,754	10,143,905
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 497,971,508 and 487,959,516 shares outstanding at Dec. 31, 2013 and 2012, respectively	1,244,929	1,219,899
Additional paid in capital	5,619,313	5,353,015
Retained earnings	2,807,983	2,413,816
Accumulated other comprehensive loss	(106,275)	(112,653)
Total common stockholders' equity	9,565,950	8,874,077
Total liabilities and equity	$33,907,490	$31,140,686

See Notes to Consolidated Financial Statements

90

Table of Contents

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

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value				
Balance at Dec. 31, 2010	482,334	$1,205,834	$5,229,075	$1,701,703	$ (53,093)	$8,083,519
Net income				841,172		841,172
Other comprehensive loss					(40,942)	(40,942)
Dividends declared:						
Cumulative preferred stock				(3,534)		(3,534)
Common stock				(503,525)		(503,525)
Premium on redemption of preferred stock				(3,260)		(3,260)
Issuances of common stock	4,160	10,400	54,514			64,914
Share-based compensation			43,854			43,854
Balance at Dec. 31, 2011	486,494	$1,216,234	$5,327,443	$2,032,556	$ (94,035)	$8,482,198
Net income				905,229		905,229
Other comprehensive loss					(18,618)	(18,618)
Dividends declared on common stock				(523,969)		(523,969)
Issuances of common stock	2,166	5,415	28,219			33,634
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity awards			(23,307)			(23,307)
Share-based compensation			37,439			37,439
Balance at Dec. 31, 2012	487,960	$1,219,899	$5,353,015	$2,413,816	$ (112,653)	$8,874,077
Net income				948,234		948,234
Other comprehensive income					6,378	6,378
Dividends declared on common stock				(554,067)		(554,067)
Issuances of common stock	10,012	25,030	237,671			262,701
Share-based compensation			28,627			28,627
Balance at Dec. 31, 2013	497,972	$1,244,929	$5,619,313	$2,807,983	$ (106,275)	$9,565,950

See Notes to Consolidated Financial Statements

Table of Contents

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

	Dec. 31 2013	2012
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	$250,000	$250,000
March 1, 2018, 5.25%	500,000	500,000
Aug. 15, 2022, 2.15%	300,000	300,000
May 15, 2023, 2.6%	400,000	—
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
Other	48	2
Unamortized discount	(11,316)	(11,362)
Total	3,888,732	3,488,640
Less current maturities	2	2
Total NSP-Minnesota long-term debt	$3,888,730	$3,488,638
PSCo		
First Mortgage Bonds, Series due:		
March 1, 2013, 4.875%	$—	$250,000
April 1, 2014, 5.5%	275,000	275,000
Sept. 1, 2017, 4.375% [(a)]	129,500	129,500
Aug. 1, 2018, 5.8%	300,000	300,000
June 1, 2019, 5.125%	400,000	400,000
Nov. 15, 2020, 3.2%	400,000	400,000
Sept. 15, 2022, 2.25%	300,000	300,000
March 15, 2023, 2.5%	250,000	—
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000
Sept. 15, 2042, 3.6%	500,000	500,000
March 15, 2043, 3.95%	250,000	—
Capital lease obligations, through 2060, 11.2% — 14.3%	179,444	185,741
Unamortized discount	(11,301)	(9,468)
Total	3,872,643	3,630,773
Less current maturities	282,143	256,297
Total PSCo long-term debt	$3,590,500	$3,374,476
SPS		
First Mortgage Bonds, Series due Aug. 15, 2041, 4.5%	$400,000	$300,000

Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Unamortized (discount) premium	(135)	3,684
Total	1,199,865	1,103,684
Less current maturities	—	—
Total SPS long-term debt	$1,199,865	$1,103,684

Table of Contents

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

	Dec. 31 2013	2012
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	$150,000	$150,000
Sept. 1, 2038, 6.375%	200,000	200,000
Oct. 1, 2042, 3.7%	100,000	100,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% [b]	18,600	18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%	558	591
Other	1,760	1,829
Unamortized discount	(2,321)	(2,457)
Total	468,597	468,563
Less current maturities	107	1,246
Total NSP-Wisconsin long-term debt	$468,490	$467,317
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2014-2050, 0% — 8.36%	$37,490	$39,984
Total	37,490	39,984
Less current maturities	1,128	2,881
Total other subsidiaries long-term debt	$36,362	$37,103
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
May 9, 2016, 0.75%	$450,000	$—
April 1, 2017, 5.613%	253,979	253,979
May 15, 2020, 4.7%	550,000	550,000
July 1, 2036, 6.5%	300,000	300,000
Sept. 15, 2041, 4.8%	250,000	250,000
Junior Subordinated Notes, Series due:		
Jan. 1, 2068, 7.6%	—	400,000
Elimination of PSCo capital lease obligation with affiliates	(72,087)	(74,358)
Unamortized discount	(7,702)	(9,205)
Total	1,724,190	1,670,416
Less current maturities (including elimination of PSCo capital lease obligation)	(2,617)	(2,271)
Total Xcel Energy Inc. long-term debt	$1,726,807	$1,672,687
Total long-term debt	$10,910,754	$10,143,905
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 497,971,508 and 487,959,516 shares outstanding at Dec. 31, 2013 and 2012, respectively	$1,244,929	$1,219,899
Additional paid in capital	5,619,313	5,353,015
Retained earnings	2,807,983	2,413,816

Accumulated other comprehensive loss	(106,275)	(112,653)
Total common stockholders’ equity	$9,565,950	$8,874,077

(a) Pollution control financing.

(b) Resource recovery financing.

See Notes to Consolidated Financial Statements

93

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

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

Principles of Consolidation — In 2013, Xcel Energy's operations included the activity of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in Xcel Energy's operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipelines, storage and compression facilities.

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

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

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

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

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

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

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

Table of Contents

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

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. The revenues and charges from these RTOs related to serving retail and wholesale electric customers comprising the native load of NSP-Minnesota and SPS are recorded on a net basis within cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales.

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

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in conserving energy and reducing peak demand on the electric and natural gas systems. These programs include efficiency and redesign programs, as well as rebates for the purchase of items such as compact fluorescent bulbs, saver switches and energy-efficient heating and cooling appliances.

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

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

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

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. Recently completed property, plant and equipment that is disallowed for cost recovery is expensed in the current period. For investments in property, plant and equipment that are 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 on abandonment is recognized, if necessary.

Table of Contents

Xcel Energy records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis 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, 2.8, and 2.9 percent for the years ended Dec. 31, 2013, 2012 and 2011, respectively.

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

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

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

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

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. The MPUC approved NSP-Minnesota's most recent triennial nuclear decommissioning studies in December 2012. These studies reflect NSP-Minnesota's plans for prompt dismantlement of the Monticello and Prairie Island facilities. These studies assume that NSP-Minnesota will be storing spent fuel on site pending removal to a U.S. government facility.

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

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

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

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

Table of Contents

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

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

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15.

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

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

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

See Note 6 for further discussion of income taxes.

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

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

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

Table of Contents

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

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

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

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in electric operating revenues in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. See Note 11 for further discussion.

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

Cash and Cash Equivalents — Xcel Energy considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of 3 months or less at the time of purchase, to be cash equivalents.

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

Inventory — All inventory is recorded at average cost.

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

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

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

Table of Contents

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

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

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

See Note 13 for further discussion of environmental costs.

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

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

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

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

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

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

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2013 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 Adopted

Balance Sheet Offsetting — In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. In January 2013, the FASB issued Balance Sheet (Topic 210) – Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities (ASU No. 2013-01) to clarify the specific instruments that should be considered in these disclosures. These disclosure requirements do not affect the presentation of amounts in the consolidated balance sheets, and were effective for annual reporting periods beginning on or after Jan. 1, 2013, and interim periods within those annual reporting periods. Xcel Energy implemented the disclosure guidance effective Jan. 1, 2013, and the implementation did not have a material impact on its consolidated financial statements. See Note 11 for the required disclosures.

Table of Contents

Comprehensive Income Disclosures — In February 2013, the FASB issued Comprehensive Income (Topic 220) — Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (ASU No. 2013-02), which requires detailed disclosures regarding changes in components of accumulated OCI and amounts reclassified out of accumulated OCI. These disclosure requirements do not change how net income or comprehensive income are presented in the consolidated financial statements. These disclosure requirements were effective for annual reporting periods beginning on or after Dec. 15, 2012, and interim periods within those annual reporting periods. Xcel Energy implemented the disclosure guidance effective Jan. 1, 2013, and the implementation did not have a material impact on its consolidated financial statements. See Note 16 for the required disclosures.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2013	Dec. 31, 2012
Accounts receivable, net		
Accounts receivable	$797,267	$769,440
Less allowance for bad debts	(53,107)	(51,394)
	$744,160	$718,046

(Thousands of Dollars)	Dec. 31, 2013	Dec. 31, 2012
Inventories		
Materials and supplies	$225,308	$213,739
Fuel	189,485	189,425
Natural gas	161,745	132,410
	$576,538	$535,574

(Thousands of Dollars)	Dec. 31, 2013	Dec. 31, 2012
Property, plant and equipment, net		
Electric plant	$30,341,310	$28,285,031
Natural gas plant	4,086,651	3,836,335
Common and other property	1,485,547	1,480,558
Plant to be retired [(a)]	101,279	152,730
CWIP	2,371,566	1,757,189
Total property, plant and equipment	38,386,353	35,511,843
Less accumulated depreciation	(12,608,305)	(12,048,697)
Nuclear fuel	2,186,799	2,090,801
Less accumulated amortization	(1,842,688)	(1,744,599)
	$26,122,159	$23,809,348

(a) As a result of the CPUC’s 2010 approval of PSCo’s CACJA compliance plan, subsequent CPCNs and the December 2013 approval of PSCo’s preferred plans for applicable generating resources, PSCo has received approval for early retirement of Cherokee Units 1, 2 and 3, Arapahoe Units 3 and 4 and Valmont Unit 5 between 2011 and 2017. In 2011, Cherokee Unit 2 was retired, in 2012, Cherokee Unit 1 was retired, and in 2013, Arapahoe Units 3 and 4 were retired. Amounts are presented net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

Table of Contents

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2013	
Borrowing limit	$2,450	
Amount outstanding at period end	759	
Average amount outstanding	515	
Maximum amount outstanding	759	
Weighted average interest rate, computed on a daily basis	0.29	%
Weighted average interest rate at period end	0.25	

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2013		Twelve Months Ended Dec. 31, 2012		Twelve Months Ended Dec. 31, 2011	
Borrowing limit	$2,450		$2,450		$2,450	
Amount outstanding at period end	759		602		219	
Average amount outstanding	481		403		430	
Maximum amount outstanding	1,160		634		824	
Weighted average interest rate, computed on a daily basis	0.31	%	0.35	%	0.36	%
Weighted average interest rate at end of period	0.25		0.36		0.40	

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2013 and 2012, there were $47.8 million and $14.2 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.45 billion and each credit facility terminates in July 2017.

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

Features of the credit facilities include:

- Xcel Energy Inc. may increase its credit facility by up to $200 million, NSP-Minnesota and PSCo may each increase their credit facilities by $100 million and SPS may increase its credit facility by $50 million. The NSP-Wisconsin credit facility cannot be increased.
-

Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at Dec. 31, 2013 and 2012, respectively, as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
	2013	2012
Xcel Energy	56 %	56 %
NSP-Wisconsin	47	50
NSP-Minnesota	47	48
SPS	49	49
PSCo	45	45

Table of Contents

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

At Dec. 31, 2013, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$800.0	$476.0	$324.0
PSCo	700.0	6.4	693.6
NSP-Minnesota	500.0	146.9	353.1
SPS	300.0	109.5	190.5
NSP-Wisconsin	150.0	68.0	82.0
Total	$2,450.0	$806.8	$1,643.2

[a] These credit facilities expire in July 2017.

[b] Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Dec. 31, 2013 and 2012.

Long-Term Borrowings and Other Financing Instruments

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

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2014	$281
2015	256
2016	656
2017	388
2018	1,206

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

- In March 2013, PSCo issued $250 million of 2.50 percent first mortgage bonds due March 15, 2023 and $250 million of 3.95 percent first mortgage bonds due March 15, 2043.
- In May 2013, Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016.
- In May 2013, NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023.
-

In August 2013, SPS issued $100 million of 4.50 percent first mortgage bonds due Aug. 15, 2041. Including the $300 million of this series previously issued, total principal outstanding for this series is $400 million.

Table of Contents

During 2012, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In June 2012, SPS issued an additional $100 million of its 4.50 percent first mortgage bonds due Aug. 15, 2041.
- In August 2012, NSP-Minnesota issued $300 million of 2.15 percent first mortgage bonds due Aug. 15, 2022, and $500 million of 3.40 percent first mortgage bonds due Aug. 15, 2042.
- In September 2012, PSCo issued $300 million of 2.25 percent first mortgage bonds due Sept. 15, 2022, and $500 million of 3.60 percent first mortgage bonds due Sept. 15, 2042.
- In October 2012, NSP-Wisconsin issued $100 million of 3.70 percent first mortgage bonds due Oct. 1, 2042.

Issuances of Common Stock — In March 2013, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $400 million of its common stock through an at-the-market offering program. No shares of common stock have been issued through this program since April 2013. As of Dec. 31, 2013, Xcel Energy Inc. had issued 7.7 million shares of common stock through this program and received cash proceeds of $223 million, net of $3 million in fees and commissions. The proceeds from the issuances of common stock were used to repay short-term debt, infuse equity into the utility subsidiaries and for other general corporate purposes.

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

Deferred Financing Costs — Other assets included deferred financing costs of approximately $83 million and $85 million, net of amortization, at Dec. 31, 2013 and 2012, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — Xcel Energy Inc. has 7,000,000 shares of preferred stock authorized to be issued with a $100 par value. At Dec. 31, 2013 and 2012, there were no shares of preferred stock outstanding.

In 2011, Xcel Energy Inc. redeemed all series of its preferred stock at an aggregate purchase price of $108 million, plus accrued dividends. The redemption premium of $3.3 million and accrued dividends are reflected as reductions of Xcel Energy's earnings available to common shareholders in the consolidated statement of income for 2011.

The charters of PSCo and SPS authorize each subsidiary to issue 10,000,000 shares of preferred stock with par values of $0.01 and $1.00 per share, respectively. At Dec. 31, 2013 and 2012, there were no preferred shares of subsidiaries outstanding.

Xcel Energy Inc. has 1,000,000,000 shares of common stock authorized to be issued with a $2.50 par value. Outstanding shares at Dec. 31, 2013 and 2012 were 497,971,508 and 487,959,516, respectively.

Dividend and Other Capital-Related Restrictions — Xcel Energy Inc.'s Articles of Incorporation place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there was no preferred stock outstanding at any time during the year ended Dec. 31, 2013, the restrictions did not place any effective limit on Xcel Energy Inc.'s ability to pay dividends.

Xcel Energy depends on its subsidiaries to pay dividends. All of Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only. Due to certain restrictive covenants, Xcel Energy Inc. is required to be current on particular interest payments before dividends can be paid.

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

Only NSP-Minnesota has a first mortgage indenture which places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than $1.4 billion and $1.3 billion in additional cash dividends to Xcel Energy Inc. at Dec. 31, 2013 and 2012, respectively.

Table of Contents

NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay by requiring an equity-to-total capitalization ratio between 46.8 percent and 57.2 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.5 percent at Dec. 31, 2013 and $912 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was $8.5 billion at Dec. 31, 2013, which did not exceed the limit of $9.0 billion.

NSP-Wisconsin cannot pay annual dividends in excess of approximately $31.2 million if its calendar year average equity-to-total capitalization ratio is or falls below the state commission authorized level of 52.5 percent, as calculated consistent with PSCW requirements. NSP-Wisconsin's calendar year average equity-to-total capitalization ratio calculated on this basis was 52.8 percent at Dec. 31, 2013 and $17.1 million in retained earnings was not restricted.

SPS' state regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc. by requiring an equity-to-total capitalization ratio (excluding short-term debt) between 45.0 percent and 55.0 percent. In addition, SPS may not pay a dividend that would cause it to lose its investment grade bond rating. SPS' equity-to-total capitalization ratio (excluding short-term debt) was 53.2 percent at Dec. 31, 2013 and $359 million in retained earnings was not restricted.

The issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC under the Federal Power Act.

- PSCo currently has authorization to issue up to an additional $1 billion of long-term debt and up to $800 million of short-term debt.
- SPS currently has no authorization to issue any long-term debt in 2014 and up to $400 million of short-term debt.
- NSP-Wisconsin currently has authorization to issue up to an additional $150 million of long-term debt and up to $150 million of short-term debt.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 46.8 percent and 57.2 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $9 billion.

Xcel Energy believes these authorizations are adequate and will seek additional authorization when necessary; however, there can be no assurance that additional authorization will be granted on the timeframe or in the amounts requested.

5. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by Xcel Energy Inc.'s utility subsidiaries in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2013:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	$596,314	$371,925	$4,533	59.0 %
Sherco Common Facilities Units 1, 2 and 3	145,579	87,289	61	80.0
Sherco Substation	4,790	2,884	—	59.0
Electric Transmission:				
Grand Meadow Line and Substation	10,647	1,225	—	50.0
CapX2020 Transmission	340,333	77,803	503,714	53.3
Total NSP-Minnesota	$1,097,663	$541,126	$508,308	

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Wisconsin				
Electric Transmission:				
CapX2020 Transmission	$13,337	$4,659	$30,199	77.9 %
La Crosse, Wis. to Madison, Wis.	—	—	5,431	50.0
Total NSP-Wisconsin	$13,337	$4,659	$35,630	

Table of Contents

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %	
PSCo					
Electric Generation:					
Hayden Unit 1	$97,879	$63,474	$53	75.5	%
Hayden Unit 2	119,972	57,875	5,563	37.4	
Hayden Common Facilities	36,916	16,055	2	53.1	
Craig Units 1 and 2	60,089	34,754	537	9.7	
Craig Common Facilities 1, 2 and 3	37,177	17,247	—	6.5	
Comanche Unit 3	877,489	63,963	581	66.7	
Comanche Common Facilities	19,812	711	2,255	82.0	
Electric Transmission:					
Transmission and other facilities, including substations	150,502	59,118	827	Various	
Gas Transportation:					
Rifle, Colo. to Avon, Colo.	16,278	6,044	—	60.0	
Total PSCo	$1,416,114	$319,241	$9,818		

NSP-Minnesota and PSCo have approximately 500 MW and 820 MW of jointly owned generating capacity, respectively. Each Company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

American Taxpayer Relief Act of 2012 — In January 2013, the American Taxpayer Relief Act of 2012 (the “Act”) was signed into law. The Act provides 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 research and experimentation (R&E) credit was extended for 2012 and 2013;
- PTCs were extended for projects that begin construction before the end of 2013; 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.

Because a change in tax law is accounted for in the period of enactment, the accounting related to the Act, including the provisions related to 2012, were recorded beginning in the first quarter of 2013. Accordingly, in 2013, Xcel Energy recorded an R&E benefit of $5 million related to 2012 and an estimated $6 million related to 2013.

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

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

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

Table of Contents

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in June 2015. 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, 2013, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $10 million of income tax expense for the 2009 through 2011 claims and the anticipated claim for 2013. Xcel Energy is continuing to work through the audit process, but the outcome and timing of a resolution are uncertain.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Dec. 31, 2013, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2008
Wisconsin	2009

In the fourth quarter of 2013, the state of Colorado completed an examination of tax years 2006 through 2009. In the first quarter of 2013, the state of Wisconsin commenced an examination of tax years 2009 through 2011. As of Dec. 31, 2013, no material adjustments had been proposed for either of these audits. There are currently no other 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, 2013	Dec. 31, 2012
Unrecognized tax benefit — Permanent tax positions	$12.9	$4.7
Unrecognized tax benefit — Temporary tax positions	28.3	29.8
Total unrecognized tax benefit	$41.2	$34.5

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

(Millions of Dollars)	2013	2012	2011
Balance at Jan. 1	$34.5	$34.7	$40.5
Additions based on tax positions related to the current year	15.1	5.2	11.9
Reductions based on tax positions related to the current year	(0.4)	(5.7)	(1.9)
Additions for tax positions of prior years	21.6	9.6	14.0
Reductions for tax positions of prior years	(4.8)	(9.3)	(2.4)
Settlements with taxing authorities	(24.8)	—	(27.3)
Lapse of applicable statutes of limitations	—	—	(0.1)
Balance at Dec. 31	$41.2	$34.5	$34.7

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, 2013	Dec. 31, 2012
NOL and tax credit carryforwards	$(27.1)	$(33.5)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS and state audits progress. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $20 million.

Table of Contents

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, 2013, 2012 and 2011 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2013, 2012 or 2011.

Tangible Property Regulations — In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with the acquisition, production and improvement of tangible property. As Xcel Energy had adopted certain utility-specific guidance previously issued by the IRS, the issuance is not expected to have a material impact on its consolidated financial statements.

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)	2013	2012
Federal NOL carryforward	$1,311	$969
Federal tax credit carryforwards	294	257
State NOL carryforwards	1,706	1,465
Valuation allowances for state NOL carryforwards	(51)	(52)
State tax credit carryforwards, net of federal detriment [a]	17	17

[a] State tax credit carryforwards are net of federal detriment of $9 million as of Dec. 31, 2013 and 2012.

The federal carryforward periods expire between 2021 and 2033. The state carryforward periods expire between 2014 and 2033.

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:

	2013	2012	2011
Federal statutory rate	35.0 %	35.0 %	35.0 %
Increases (decreases) in tax from:			
Tax credits recognized, net of federal income tax expense	(2.6)	(2.2)	(2.6)
Regulatory differences — utility plant items	(1.6)	(1.0)	(0.8)
NOL carryback	(0.8)	(1.1)	—
State income taxes, net of federal income tax benefit	4.1	4.0	4.3
Change in unrecognized tax benefits	0.6	—	(0.1)
Prescription drug tax benefit and Medicare Part D	—	(1.2)	—
Other, net	(0.9)	(0.3)	—
Effective income tax rate	33.8 %	33.2 %	35.8 %

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

(Thousands of Dollars)	2013	2012	2011
Current federal tax (benefit) expense	$(46,173)	$7,876	$3,399
Current state tax expense	7,678	31,478	9,971
Current change in unrecognized tax expense (benefit)	13,162	(1,704)	(8,266)
Deferred federal tax expense	439,085	366,409	383,931
Deferred state tax expense	80,907	50,741	78,770
Deferred change in unrecognized tax (benefit) expense	(4,930)	2,013	6,705
Deferred investment tax credits	(5,753)	(6,610)	(6,194)
Total income tax expense	$483,976	$450,203	$468,316

107

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

(Thousands of Dollars)	2013	2012	2011
Deferred tax expense excluding items below	$588,053	$559,860	$446,893
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(64,420)	(63,862)	(7,108)
Tax (expense) benefit allocated to OCI	(8,572)	12,102	26,798
Other	1	(6)	(16)
Deferred tax expense	$515,062	$508,094	$466,567

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

(Thousands of Dollars)	2013	2012
Deferred tax liabilities:		
Differences between book and tax bases of property	$5,562,446	$4,867,142
Regulatory assets	321,636	293,367
Other	254,639	220,781
Total deferred tax liabilities	$6,138,721	$5,381,290
Deferred tax assets:		
NOL carryforward	$532,774	$430,765
Tax credit carryforward	311,388	273,776
Unbilled revenue - fuel costs	58,908	60,068
Rate refund	49,804	8,109
Environmental remediation	42,886	44,549
Regulatory liabilities	40,947	34,471
Deferred investment tax credits	34,231	35,767
Other	81,202	95,308
NOL and tax credit valuation allowances	(3,263)	(3,314)
Total deferred tax assets	$1,148,877	$979,499
Net deferred tax liability	$4,989,844	$4,401,791

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents), were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated based on the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements.

Common stock equivalents related to share-based compensation causing dilutive impact to EPS relates to commitments to issue common stock as an employer match to 401(k) plan participants. In October 2013, Xcel Energy determined that it would settle the 2013 401(k) employer match in cash instead of common stock for all employee groups except PSCo bargaining employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

Table of Contents

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- RSU equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- PSP liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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

	2013			2012			2011		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$948,234			$905,229			$841,172		
Less: Dividend requirements on preferred stock	—			—			(3,534)		
Less: Premium on redemption of preferred stock	—			—			(3,260)		
Basic earnings per share:									
Earnings available to common shareholders	948,234	496,073	$ 1.91	905,229	487,899	$ 1.86	834,378	485,039	$ 1.72
Effect of dilutive securities:									
401(k) equity awards	—	459		—	535		—	576	
Diluted earnings per share:									
Earnings available to common shareholders	$948,234	496,532	$ 1.91	$905,229	488,434	$ 1.85	$834,378	485,615	$ 1.72

No stock options were outstanding during 2013 and 2012. In 2011, Xcel Energy Inc. had approximately 2.1 million weighted average options outstanding that were antidilutive, and therefore, excluded from the EPS calculation.

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

8. Share-Based Compensation

Stock Options — Xcel Energy Inc. has incentive compensation plans under which stock options and other incentives are awarded to key employees. Xcel Energy Inc. has not granted stock options since 2001. There were no stock options outstanding and no stock option activity during 2013 and 2012.

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

(Awards in Thousands)	2011 Awards	Average Exercise Price
Outstanding and exercisable at Jan. 1	2,498	$30.42
Exercised	(1,173)	25.90
Expired	(1,325)	34.42
Outstanding and exercisable at Dec. 31	—	—

Table of Contents

The total market value and the total intrinsic value of stock options exercised were as follows for the year ended Dec. 31:

(Thousands of Dollars)	2011
Market value of exercises	$30,761
Intrinsic value of options exercised [(a)]	380

[(a)] Intrinsic value is calculated as market price at exercise date less the option exercise price.

Cash received from stock options exercised and the actual tax benefit realized for the tax deductions from stock options exercised during the year ended Dec. 31 were as follows:

(Thousands of Dollars)	2011
Cash received from stock options exercised	$30,381
Tax benefit realized for the tax deductions from stock options exercised	157

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock vests and settles in equal annual installments over a three-year period. Xcel Energy Inc. reinvests dividends on the restricted stock while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Xcel Energy Inc. granted shares of restricted stock for the years ended Dec. 31 as follows:

(Shares in Thousands)	2013	2012	2011
Granted shares	33	33	15
Grant date fair value	$28.30	$26.43	$23.62

A summary of the changes of nonvested restricted stock for the year ended 2013 were as follows:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2013	54	$24.85
Granted	33	28.30
Vested	(27)	23.65
Dividend equivalents	2	28.88
Nonvested restricted stock at Dec. 31, 2013	62	27.33

RSUs — Xcel Energy Inc.'s Board of Directors has granted RSUs under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated in 2010). The plan allows the attachment of various performance goals to the RSUs granted. The performance goals may vary by plan year. At the end of the restricted performance period, such grants will be awarded if the performance goals are met. If the goals are not achieved by the end of the restricted performance period, all associated RSUs and dividend equivalents are forfeited.

For RSUs issued in 2010, if the performance criteria have not been met within four years of the grant date, all RSUs, plus associated dividend equivalents, shall be forfeited. The performance conditions for RSUs granted in 2011 and 2012, and most granted in 2013 will be measured three years after the grant date, at which time the RSUs, plus associated dividend equivalents, will either be settled or forfeited. In 2013, approximately 0.2 million RSUs were granted subject to service conditions, but no performance conditions. Payout of all other RSUs and the lapsing of restrictions on the transfer of units are based on one of two separate performance criteria.

The performance conditions for a portion of the awarded units are based on EPS growth, with an additional condition that Xcel Energy Inc.’s annual dividend paid on its common stock remains at a specified amount per share or greater. These RSUs issued in 2011, 2012 and 2013, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years, with potential payouts ranging from zero to 150 percent, depending on the level of EPS growth.

Table of Contents

The performance conditions for the remaining performance-based units are based on environmental goals. These RSUs issued in 2011, 2012 and 2013, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years with potential payouts ranging from zero to 150 percent, depending on the level of environmental performance, based on established indicators.

The 2010 RSUs measured on EPS growth and all 2009 RSUs met their targets as of Dec. 31, 2011, and were settled in shares in February 2012. The 2010 environmental RSUs met their targets as of Dec. 31, 2012 and were settled in shares in February 2013. The 2011 RSUs measured on EPS growth and the 2011 environmental RSUs met their targets as of Dec. 31, 2013 and will be settled in shares in February 2014.

The RSUs granted for the years ended Dec. 31 were as follows:

(Units in Thousands)	2013	2012	2011
Granted units	774	591	828
Weighted average grant date fair value	$27.65	$27.35	$23.63

A summary of the changes of nonvested RSUs for the year ended 2013, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested RSUs at Jan. 1, 2013	1,155	$25.41
Granted	774	27.65
Forfeited	(81)	26.32
Vested	(600)	23.62
Dividend equivalents	64	26.11
Nonvested RSUs at Dec. 31, 2013	1,312	27.53

The total fair value of nonvested RSUs as of Dec. 31, 2013 was $36.7 million and the weighted average remaining contractual life was 1.7 years.

Approximately 0.6 million RSUs vested during 2013 at a total fair value of $16.8 million. Approximately 0.1 million RSUs vested during 2012 at a total fair value of $1.2 million. Approximately 1.1 million RSUs vested during 2011 at a total fair value of $30.1 million.

Stock Equivalent Unit Plan — Non-employee members of the Xcel Energy Inc. Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy Inc. common stock. The annual grants are vested as of the date of each member's election to the board of directors; there is no further service or other condition attached to the annual grants after the member has been elected to the board. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash, and similarly have no further service or other conditions attached. Dividends on Xcel Energy Inc.'s common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy Inc.'s common stock upon a director's termination of service.

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

(Units in Thousands)	2013	2012	2011
Granted units	69	65	60
Grant date fair value	$29.52	$27.41	$25.12

111

Table of Contents

A summary of the stock equivalent unit changes for the year ended 2013 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2013	577	$21.71
Granted	69	29.52
Units distributed	(32)	18.23
Dividend equivalents	22	29.06
Stock equivalent units at Dec. 31, 2013	636	22.98

PSP Awards — Xcel Energy Inc.'s Board of Directors has granted PSP awards under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated effective in 2010). The plan allows Xcel Energy to attach various performance goals to the PSP awards granted. The PSP awards have been historically dependent on a single measure of performance, Xcel Energy Inc.'s TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to the TSR of other companies in the EEI Investor-Owned Electrics index. At the end of the three-year period, potential payouts of the PSP awards range from zero to 200 percent, depending on Xcel Energy Inc.'s TSR compared to the peer group.

The PSP awards granted for the years ended Dec. 31 were as follows:

(In Thousands)	2013	2012	2011
Awards granted	215	161	311

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

(In Thousands)	2013	2012	2011
Awards settled	108	286	305
Settlement amount (cash and common stock)	$3,057	$7,554	$7,200

The amount of cash used to settle Xcel Energy's PSP awards was $1.5 million, $3.8 million and $3.6 million in 2013, 2012 and 2011, respectively.

Share-Based Compensation Expense — The vesting of the RSUs is generally predicated on the achievement of a performance condition, which is the achievement of an EPS or environmental measures target. Additionally, approximately 0.2 million of RSUs were granted in 2013 with vesting subject only to service conditions for periods up to five years. RSU awards and restricted stock are considered to be equity awards, since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. The grant date fair value of RSUs and restricted stock is expensed over the service period as employees vest in their rights to those awards.

The PSP awards have been historically settled partially in cash, and therefore, do not qualify as equity awards, but rather are accounted for as liability awards. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance conditions, and final expense is based on the market value of the shares on the date the award is settled.

Table of Contents

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

(Thousands of Dollars)	2013	2012	2011
Compensation cost for share-based awards [(a) (b) (c)]	$24,613	$26,970	$45,006
Tax benefit recognized in income	9,571	10,513	17,559
Capitalized compensation cost for share-based awards	1,698	4,270	3,857

(a) Compensation costs for share-based payment arrangements is included in O&M expense in the consolidated statements of income.

(b) Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totaled $7.0 million, $22.2 million and $21.6 million for the years ended 2013, 2012 and 2011, respectively.

(c) In October 2013, Xcel Energy determined that it would settle the 2013 401(k) employer match in cash instead of common stock for all employee groups except PSCo bargaining employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated effective Feb. 17, 2010) is 8.3 million shares. Under the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010), the total number of shares approved for issuance is 1.2 million shares.

As of Dec. 31, 2013 and 2012, there was approximately $22.1 million and $15.3 million, respectively, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the amount unrecognized at Dec. 31, 2013 over a weighted average period of 1.8 years.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 48 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2013:

- NSP-Minnesota had 2,022 and NSP-Wisconsin had 399 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 248 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates in 2015 and 2016.
- PSCo had 2,086 bargaining employees covered under a collective-bargaining agreement, which expires in May 2014.
- SPS had 832 bargaining employees covered under a collective-bargaining agreement, which expires in October 2014.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

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

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

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

Specific valuation methods include the following:

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

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. Preferred stock is valued using recent trades and quoted prices of similar securities. The fair values for commingled funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on the plan's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee's average pay and social security benefits. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

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, 2013 and 2012 were $36.5 million and $39.4 million, respectively. In 2013 and 2012, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $6.6 million and $15.6 million, respectively. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The pension cost determination assumes a forecasted mix of investment types over the long-term. Investment returns were below the assumed level of 6.88 percent in 2013 and above the assumed levels of 7.10 and 7.50 percent in 2012 and 2011, respectively. Xcel Energy continually reviews its pension assumptions. In 2014, Xcel Energy's expected investment return assumption is 7.05 percent.

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

Table of Contents

The following table presents the target pension asset allocations for Xcel Energy:

	2013	2012
Domestic and international equity securities	30 %	25 %
Long-duration fixed income and interest rate swap securities	33	40
Short-to-intermediate fixed income securities	15	10
Alternative investments	20	23
Cash	2	2
Total	100 %	100 %

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2013 and 2012:

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

	Dec. 31, 2012			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$164,096	$—	$—	$164,096
Derivatives	—	12,955	—	12,955
Government securities	—	298,141	—	298,141
Corporate bonds	—	622,597	—	622,597
Asset-backed securities	—	—	14,639	14,639
Mortgage-backed securities	—	—	39,904	39,904
Common stock	73,247	—	—	73,247
Private equity investments	—	—	158,498	158,498
Commingled funds	—	1,524,563	—	1,524,563
Real estate	—	—	64,597	64,597
Securities lending collateral obligation and other	—	(29,454)	—	(29,454)
Total	$237,343	$2,428,802	$277,638	$2,943,783

115

Table of Contents

The following tables present the changes in Xcel Energy's Level 3 pension plan assets for the years ended Dec. 31, 2013, 2012 and 2011:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 [(a)]	Dec. 31, 2013
Asset-backed securities	$14,639	$—	$—	$—	$(14,639)	$—
Mortgage-backed securities	39,904	—	—	—	(39,904)	—
Private equity investments	158,498	22,058	(24,335)	(3,372)	—	152,849
Real estate	64,597	(2,659)	8,690	9,317	(32,392)	47,553
Total	$277,638	$19,399	$(15,645)	$5,945	$(86,935)	$200,402

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

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

(Thousands of Dollars)	Jan. 1, 2011	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2011
Asset-backed securities	$26,986	$2,391	$(2,504)	$4,495	$—	$31,368
Mortgage-backed securities	113,418	1,103	(5,926)	(35,073)	—	73,522
Private equity investments	122,223	3,971	12,412	20,757	—	159,363
Real estate	73,701	(629)	20,271	(56,237)	—	37,106
Total	$336,328	$6,836	$24,253	$(66,058)	$—	$301,359

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

(Thousands of Dollars)	2013	2012
Accumulated Benefit Obligation at Dec. 31	$3,282,651	$3,475,154
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$3,639,530	$3,226,219
Service cost	96,282	86,364
Interest cost	140,690	157,035
Plan amendments	(4,120)	6,240
Actuarial (gain) loss	(153,338)	400,429
Benefit payments	(278,340)	(236,757)
Obligation at Dec. 31	$3,440,704	$3,639,530

(Thousands of Dollars)	2013	2012
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$2,943,783	$2,670,280

Actual return on plan assets	152,259	312,167
Employer contributions	192,438	198,093
Benefit payments	(278,340)	(236,757)
Fair value of plan assets at Dec. 31	$3,010,140	$2,943,783

116

Table of Contents

(Thousands of Dollars)	2013	2012
Funded Status of Plans at Dec. 31:		
Funded status [(a)]	$(430,564)	$(695,747)

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

(Thousands of Dollars)	2013	2012
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$1,549,474	$1,800,770
Prior service credit	(12,624)	(2,633)
Total	$1,536,850	$1,798,137

(Thousands of Dollars)	2013	2012
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	$125,702	$115,811
Noncurrent regulatory assets	1,343,432	1,606,524
Deferred income taxes	26,403	31,075
Net-of-tax accumulated OCI	41,313	44,727
Total	$1,536,850	$1,798,137
Measurement date	Dec. 31, 2013	Dec. 31, 2012

	2013	2012
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.75 %	4.00 %
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP 2000	RP 2000

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. These regulations did not require cash funding for 2008 through 2010 for Xcel Energy's pension plans. Required contributions were made in 2011, 2012 and 2013 to meet minimum funding requirements.

The following are the pension funding contributions, both voluntary and required, made by Xcel Energy for 2011 through January 2014:

- In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans;
- In 2013, contributions of $192.4 million were made across four of Xcel Energy's pension plans;
- In 2012, contributions of $198.1 million were made across four of Xcel Energy's pension plans;
- In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans;
- For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments —The 2013 decrease of the projected benefit obligation for plan amendments is due to fully insuring the long-term disability benefit for NSP bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan. In 2012, the plan was amended to allow a one time transfer of a portion of qualifying obligations from the nonqualified pension plan into the qualified pension plans. Xcel Energy also modified the benefit formula for nonbargaining new hires beginning in 2012 to a reduced benefit level.

Table of Contents

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

(Thousands of Dollars)	2013	2012	2011
Service cost	$96,282	$86,364	$77,319
Interest cost	140,690	157,035	161,412
Expected return on plan assets	(198,452)	(207,095)	(221,600)
Amortization of prior service cost	5,871	21,065	22,533
Amortization of net loss	144,151	108,982	78,510
Net periodic pension cost	188,542	166,351	118,174
Costs not recognized due to effects of regulation	(36,724)	(39,217)	(37,198)
Net benefit cost recognized for financial reporting	$151,818	$127,134	$80,976

	2013	2012	2011
Significant Assumptions Used to Measure Costs:			
Discount rate	4.00 %	5.00 %	5.50 %
Expected average long-term increase in compensation level	3.75	4.00	4.00
Expected average long-term rate of return on assets	6.88	7.10	7.50

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 2014 pension cost calculations is 7.05 percent.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately $30.3 million in 2013, $28.0 million in 2012 and $27.1 million in 2011.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- The former NSP, which includes NSP-Minnesota and NSP-Wisconsin, discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for former NCE, which includes PSCo and SPS, nonbargaining employees retiring after June 30, 2003.
- Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

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

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs. The Colorado jurisdictional postretirement benefit costs deferred during the transition period were amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. PSCo transitioned to full accrual accounting for postretirement benefit costs between 1993 and 1997.

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Table of Contents

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

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2013 and 2012:

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

	Dec. 31, 2012			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$91,278	$—	$—	$91,278
Derivatives	—	4	—	4
Government securities	—	73,449	—	73,449
Insurance contracts	—	50,008	—	50,008
Corporate bonds	—	43,810	—	43,810
Asset-backed securities	—	—	757	757
Mortgage-backed securities	—	—	39,958	39,958
Commingled funds	—	228,423	—	228,423
Other	—	(46,845)	—	(46,845)
Total	$91,278	$348,849	$40,715	$480,842

The following tables present the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the years ended Dec. 31, 2013, 2012 and 2011:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 [(a)]	Dec. 31, 2013
Asset-backed securities	$757	$—	$—	$—	$(757)	$—
Mortgage-backed securities	39,958	—	—	—	(39,958)	—
Total	$40,715	$—	$—	$—	$(40,715)	$—

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

Table of Contents

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

(Thousands of Dollars)	Jan. 1, 2011	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2011
Asset-backed securities	$2,585	$(10)	$(664)	$5,956	$—	$7,867
Mortgage-backed securities	19,212	(1,669)	2,623	7,087	—	27,253
Private equity investments	—	12	53	414	—	479
Real estate	—	(2)	(34)	180	—	144
Total	$21,797	$(1,669)	$1,978	$13,637	$—	$35,743

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

(Thousands of Dollars)	2013	2012
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$851,952	$776,847
Service cost	4,079	4,203
Interest cost	32,141	37,861
Medicare subsidy reimbursements	1,197	3,741
Plan amendments	(14,571)	(41,128)
Plan participants' contributions	9,580	14,241
Actuarial (gain) loss	(103,359)	119,949
Benefit payments	(49,591)	(63,762)
Obligation at Dec. 31	$731,428	$851,952

(Thousands of Dollars)	2013	2012
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$480,842	$426,835
Actual return on plan assets	33,644	56,385
Plan participants' contributions	9,580	14,241
Employer contributions	17,561	47,143
Benefit payments	(49,591)	(63,762)
Fair value of plan assets at Dec. 31	$492,036	$480,842

(Thousands of Dollars)	2013	2012
Funded Status of Plans at Dec. 31:		
Funded status	$(239,392)	$(371,110)
Current liabilities	(6,807)	(6,070)
Noncurrent liabilities	(232,585)	(365,040)
Net postretirement amounts recognized on consolidated balance sheets	$(239,392)	$(371,110)

(Thousands of Dollars)	2013	2012
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$195,630	$321,946

Prior service credit	(86,298)	(84,228)
Transition obligation	2	827
Total	$109,334	$238,545

Table of Contents

(Thousands of Dollars)	2013	2012
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	$12,102	$6,930
Noncurrent regulatory assets	99,071	226,052
Current regulatory liabilities	(319)	(954)
Noncurrent regulatory liabilities	(8,858)	(3,453)
Deferred income taxes	2,965	4,050
Net-of-tax accumulated OCI	4,373	5,920
Total	$109,334	$238,545
Measurement date	Dec. 31, 2013	Dec. 31, 2012

	2013	2012
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.82 %	4.10 %
Mortality table	RP 2000	RP 2000
Health care costs trend rate — initial	7.00	7.50

Effective Jan. 1, 2014, the initial medical trend rate was decreased from 7.5 percent to 7.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is five years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

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

	One-Percentage Point	
(Thousands of Dollars)	Increase	Decrease
APBO	$75,617	$(63,360)
Service and interest components	3,580	(2,826)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy contributed $17.6 million during 2013, $47.1 million during 2012, $49.0 million during 2011 and expects to contribute approximately $13.3 million during 2014.

Plan Amendments — The 2013 decrease of the projected Xcel Energy and PSCo postretirement health and welfare benefit obligation for plan amendments is due to changes in the participant co-pay structure for certain retiree groups. The 2012 decrease of the projected Xcel Energy and PSCo postretirement health and welfare benefit obligation for plan amendments is due to the expected transition of certain participant groups to an external plan administrator.

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

(Thousands of Dollars)	2013	2012	2011
Service cost	$4,079	$4,203	$4,824
Interest cost	32,141	37,861	42,086
Expected return on plan assets	(33,011)	(28,409)	(31,962)
Amortization of transition obligation	825	14,320	14,444
Amortization of prior service credit	(12,501)	(7,552)	(4,932)
Amortization of net loss	22,325	16,906	13,294
Net periodic postretirement benefit cost	13,858	37,329	37,754

Additional cost recognized due to effects of regulation	—	3,891	3,891
Net benefit cost recognized for financial reporting	$13,858	$41,220	$41,645

Table of Contents

	2013		2012		2011	
Significant Assumptions Used to Measure Costs:						
Discount rate	4.10	%	5.00	%	5.50	%
Expected average long-term rate of return on assets	7.11		6.75		7.50	

Projected Benefit Payments

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

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2014	$313,226	$53,516	$2,627	$50,889
2015	266,802	54,576	2,806	51,770
2016	267,186	55,965	2,969	52,996
2017	269,526	56,513	3,135	53,378
2018	272,908	58,181	3,291	54,890
2019-2023	1,339,764	282,860	18,274	264,586

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2013, 2012 and 2011. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans increased to approximately 1,100 in 2013 from approximately 800 in 2012. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota and NSP-Wisconsin in multiemployer plans for the years presented:

(Thousands of Dollars)	2013	2012	2011
Multiemployer pension contributions:			
NSP-Minnesota	$23,515	$14,984	$17,811
NSP-Wisconsin	130	163	169
Total	$23,645	$15,147	$17,980
Multiemployer other postretirement benefit contributions:			
NSP-Minnesota	$390	$197	$336
Total	$390	$197	$336

10. Other Income, Net

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

(Thousands of Dollars)	2013	2012	2011

Interest income	$8,343	$10,327	$10,639
Other nonoperating income	3,025	3,483	3,722
Insurance policy expense	(8,292)	(7,365)	(4,785)
Other nonoperating expense	(104)	(270)	(321)
Other income, net	$2,972	$6,175	$9,255

Table of Contents

11. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments purchased from MISO, PJM, ERCOT and NYISO, generally referred to as FTRs. Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in the FCA as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island 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 $240.3 million and $135.8 million at Dec. 31, 2013 and 2012, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $58.5 million and $46.4 million at Dec. 31, 2013 and 2012, respectively.

Table of Contents

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2013 and 2012:

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

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

	Dec. 31, 2012				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$246,904	$237,938	$8,966	$—	$246,904
Commingled funds	396,681	—	417,583	—	417,583
International equity funds	66,452	—	69,481	—	69,481
Private equity investments	27,943	—	—	33,250	33,250
Real estate	32,561	—	—	39,074	39,074
Debt securities:					
Government securities	21,092	—	21,521	—	21,521
U.S. corporate bonds	162,053	—	169,488	—	169,488
International corporate bonds	15,165	—	16,052	—	16,052
Municipal bonds	21,392	—	23,650	—	23,650
Asset-backed securities	2,066	—	—	2,067	2,067
Mortgage-backed securities	28,743	—	—	30,209	30,209
Equity securities:					
Common stock	379,093	420,263	—	—	420,263
Total	$1,400,145	$658,201	$726,741	$104,600	$1,489,542

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $91.2 million of equity investments in unconsolidated subsidiaries and $37.1 million of miscellaneous investments.

Table of Contents

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

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets and Liabilities	Transfers Out of Level 3 [(a)]	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) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

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

(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	Transfers Out of Level 3	Dec. 31, 2011
Private equity investments	$—	$9,203	$—	$—	$—	$9,203
Real estate	—	24,768	—	1,627	—	26,395
Asset-backed securities	33,174	16,518	(32,560)	(631)	—	16,501
Mortgage-backed securities	72,589	168,688	(161,134)	(1,479)	—	78,664
Total	$105,763	$219,177	$(193,694)	$(483)	$—	$130,763

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2013:

	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	$—	$—	$—	$27,628	$27,628
U.S. corporate bonds	780	17,850	63,089	1,819	83,538
International corporate bonds	—	2,222	13,136	—	15,358
Municipal bonds	3,554	25,663	33,109	169,690	232,016
Debt securities	$4,334	$45,735	$109,334	$199,137	$358,540

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

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

Table of Contents

At Dec. 31, 2013, accumulated other comprehensive losses related to interest rate derivatives included $2.3 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.

In conjunction with the NSP-Minnesota debt issuance in August 2012, NSP-Minnesota settled interest rate hedging instruments with a notional amount of $225 million with cash payments of $45.0 million. In conjunction with the PSCo debt issuance in September 2012, PSCo settled interest rate hedging instruments with a notional amount of $250 million with cash payments of $44.7 million. These losses are classified as a component of accumulated other comprehensive loss on the consolidated balance sheet, net of tax, and are being reclassified to earnings over the term of the hedged interest payments. See Note 4 for further discussion of long-term borrowings.

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

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and vehicle fuel.

At Dec. 31, 2013, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2013 and 2012.

At Dec. 31, 2013, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31, 2013 and 2012:

(Amounts in Thousands) [(a)(b)]	Dec. 31, 2013	Dec. 31, 2012
MWh of electricity	58,423	55,976
MMBtu of natural gas	9,854	725
Gallons of vehicle fuel	482	682

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

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

Table of Contents

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At Dec. 31, 2013, four of Xcel Energy's 10 most significant counterparties for these activities, comprising $49.3 million or 18 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. The remaining six significant counterparties, comprising $68.1 million or 25 percent of this credit exposure at Dec. 31, 2013, were not rated by these agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. All 10 of these significant counterparties are municipal or cooperative electric entities or other utilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2013	2012	2011
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(61,241)	$(45,738)	$(8,094)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	12	(19,200)	(38,292)
After-tax net realized losses on derivative transactions reclassified into earnings	1,476	3,697	648
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$(59,753)	$(61,241)	$(45,738)

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2013, 2012 and 2011, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and(Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$4,107 (a)	$ —	$—
Vehicle fuel and other commodity	29	—	(90) (b)	—	—
Total	$29	$—	$4,017	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$11,221 (c)
Electric commodity	—	75,817	—	(52,796) (d)	—
Natural gas commodity	—	(3,088)	—	5,019 (e)	(6,589) (d)
Total	$—	$72,729	$—	$ (47,777)	$4,632

Table of Contents

	Year Ended Dec. 31, 2012				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$(31,913)	$—	$6,582 [a]	$—	$—
Vehicle fuel and other commodity	120	—	(198) [b]	—	—
Total	$(31,793)	$—	$6,384	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$12,226 [c]
Electric commodity	—	44,162	—	(39,999) [d]	—
Natural gas commodity	—	(10,809)	—	80,902 [e]	(137) [d]
Total	$—	$33,353	$—	$40,903	$12,089

	Year Ended Dec. 31, 2011				
	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	$(63,573)	$—	$1,424 [a]	$ —	$—
Vehicle fuel and other commodity	195	—	(178) [b]	—	—
Total	$(63,378)	$—	$1,246	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$6,418 [c]
Electric commodity	—	49,818	—	(40,492) [d]	—
Natural gas commodity	—	(111,574)	—	91,743 [e]	(382) [d]
Total	$—	$(61,756)	$—	$ 51,251	$6,036

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts for the years ended Dec. 31, 2012 and 2011 included $5.0 million and $12.7 million, respectively, of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses for the year ended Dec. 31, 2013 were immaterial. The remaining settlement losses for the years ended Dec. 31, 2013, 2012 and 2011 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2013, 2012 and 2011. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Table of Contents

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, derivative instruments reflected in a $1.4 million and $4.6 million gross liability position on the consolidated balance sheets at Dec. 31, 2013 and 2012, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $1.4 million and $4.6 million at Dec. 31, 2013 and 2012, respectively. At Dec. 31, 2013 and 2012, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2013 and 2012.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2013:

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

130

Table of Contents

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

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2013. At Dec. 31, 2013, derivative assets and liabilities include obligations to return cash collateral of $0.2 million and rights to reclaim cash collateral of $4.2 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2012:

(Thousands of Dollars)	Dec. 31, 2012 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$95	$—	$95	$—	$95
Other derivative instruments:						
Commodity trading	—	26,303	692	26,995	(6,675)	20,320
Electric commodity	—	—	16,724	16,724	(843)	15,881
Natural gas commodity	—	7	—	7	(7)	—
Total current derivative assets	$—	$26,405	$17,416	$43,821	$(7,525)	36,296
PPAs [a]						32,717
Current derivative instruments						$69,013
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						

Vehicle fuel and other commodity	$—	$86	$—	$86	$(47)	$39
Other derivative instruments:						
Commodity trading	—	41,282	77	41,359	(4,162)	37,197
Total noncurrent derivative assets	$—	$41,368	$77	$41,445	$(4,209)	37,236
PPAs [a]						89,061
Noncurrent derivative instruments						$126,297

131

Table of Contents

(Thousands of Dollars)	Dec. 31, 2012 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$18,622	$1	$18,623	$(9,112)	$9,511
Electric commodity	—	—	843	843	(843)	—
Natural gas commodity	—	98	—	98	(7)	91
Total current derivative liabilities	$—	$18,720	$844	$19,564	$(9,962)	9,602
PPAs [a]						22,880
Current derivative instruments						$32,482
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$21,417	$—	$21,417	$(4,210)	$17,207
Total noncurrent derivative liabilities	$—	$21,417	$—	$21,417	$(4,210)	17,207
PPAs [a]						225,659
Noncurrent derivative instruments						$242,866

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2012. At Dec. 31, 2012, derivative assets and liabilities include obligations to return cash collateral of $0.6 million and rights to reclaim cash collateral of $3.0 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, 2013, 2012 and 2011:

(Thousands of Dollars)	Year Ended Dec. 31 2013	2012	2011
Balance at Jan. 1	$16,649	$12,417	$2,392
Purchases	61,474	37,595	33,609
Settlements	(45,199)	(44,950)	(36,555)
Net transactions recorded during the period:			
Gains recognized in earnings [a]	3,947	463	69
Gains recognized as regulatory assets and liabilities	4,789	11,124	12,902
Balance at Dec. 31	$41,660	$16,649	$12,417

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

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2013, 2012 and 2011.

Fair Value of Long-Term Debt

As of Dec. 31, 2013 and 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	2013 Carrying Amount	Fair Value	2012 Carrying Amount	Fair Value
Long-term debt, including current portion	$11,191,517	$11,878,643	$10,402,060	$12,207,866

Table of Contents

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2013 and 2012, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

12. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — On Nov. 4, 2013, NSP-Minnesota filed a two-year, electric rate case with the MPUC. The rate case is based on a requested ROE of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015.

The NSP-Minnesota electric rate case reflects an overall increase in revenues of approximately $193 million or 6.9 percent in 2014 and an additional $98 million or 3.5 percent in 2015. The request includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, the impact of NSP-Minnesota's request on customer bills would result in a 4.6 percent increase in 2014 and an additional 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess theoretical depreciation reserve which the MPUC approved in NSP-Minnesota's last electric rate case and the use of expected funds from the DOE for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund its decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello LCM/EPU project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island EPU project. NSP-Minnesota plans to file a petition for deferred accounting regarding these Monticello costs in the first quarter of 2014.

The rate request, moderation plan, interim rate adjustments, customer bill impacts and certain impacts on expenses are detailed in the table below:

(Millions of Dollars)	2014	Percentage Increase	2015	Percentage Increase
Pre-moderation deficiency	$274		$81	
Moderation change compared to prior year:				
Excess theoretical depreciation reserve	(81)		53	
DOE settlement proceeds	—		(36)	
Filed rate request	193	6.9%	98	3.5%
Interim rate adjustments	(66)		66	
Impact on customer bill	127	4.6%	164	5.6%
Potential expense deferral (Monticello/Prairie Island EPU projects)	16		—	
Depreciation expense - reduction/(increase)	81		(46)	
Recognition of DOE settlement proceeds	—		36	
Pre-tax impact on operating income	$224		$154	

On Dec. 12, 2013, the MPUC approved interim rates of $127 million as requested, effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the theoretical depreciation reserve amortization was a permissible adjustment to its interim rate request even though it differed from the MPUC's 2013 Minnesota rate case order.

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

- Direct Testimony — June 5, 2014;
- Rebuttal Testimony — July 7, 2014;
- Surrebuttal Testimony — Aug. 4, 2014;
- Evidentiary Hearing — Aug. 11-18, 2014;

Table of Contents

- Reply Brief — Oct. 14, 2014; and
- ALJ Report — Dec. 22, 2014.

A final MPUC decision is anticipated in March 2015.

NSP-Minnesota – Minnesota 2013 Electric Rate Case — In November 2012, NSP-Minnesota filed a request with the MPUC for an increase in annual revenues of approximately $285 million, or 10.7 percent. The rate filing was based on a 2013 FTY, a requested ROE of 10.6 percent, an average electric rate base of approximately $6.3 billion and an equity ratio of 52.56 percent. In January 2013, interim rates of approximately $251 million became effective, subject to refund.

In May 2013, NSP-Minnesota subsequently revised the requested annual revenue increase to approximately $209 million, or 7.8 percent, based on an ROE of 10.6 percent, a rate base of approximately $6.3 billion an equity ratio of 52.56 percent. The revenue requirement reflected a requested deficiency of $259 million combined with $50 million of rate mitigation through deferral mechanisms.

In September 2013, the MPUC issued an order approving a rate increase of approximately $103 million, or 3.8 percent, based on a 9.83 percent ROE and 52.56 percent equity ratio. In addition, the MPUC authorized approximately $20 million in deferrals, as well as a $24 million reduction in revenue and depreciation expense.

The table below reconciles NSP-Minnesota's original request to the final MPUC order:

(Millions of Dollars)	MPUC Order
NSP-Minnesota original request	$285
ROE	(43)
Sherco Unit 3	(34)
Reduced recovery for nuclear plants	(15)
Incentive compensation	(4)
Sales forecast	(26)
Pension	(13)
Employee benefits	(6)
Black Dog remediation	(5)
Estimated impact of the theoretical depreciation reserve	(24)
NSP-Wisconsin wholesale allocation	(7)
Other, net	(5)
Recommended rate increase	103
Estimated impact of cost deferrals	20
Estimated impact of the theoretical depreciation reserve	24
Impact on pre-tax income	$147

NSP-Minnesota filed its final rate implementation and interim rate refund compliance filing on Sept. 19, 2013, requesting final rates be implemented Dec. 1, 2013, with interim rate refunds of approximately $132.2 million, including interest, to begin by January 2014. On Nov. 19, 2013, the MPUC approved the final rate implementation plan, new rates began Dec. 1, 2013 and interim rate refunds were applied to customer accounts starting Dec. 16, 2013.

Table of Contents

NSP-Minnesota Nuclear Project Prudence Investigation — The MPUC has initiated an investigation to determine whether the costs in excess of those included in the CON for NSP-Minnesota's Monticello LCM/EPU project were prudent. In October 2013, NSP-Minnesota filed a summary report to further support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional NRC licensing related requests over the five-plus year application process. NSP-Minnesota has provided information that the cost deviation is in line with similar upgrade projects undertaken by other utilities and the project remains economically beneficial to customers. The results and any recommendations from the conclusion of this prudence proceeding are expected to be considered by the MPUC in NSP-Minnesota's 2014 Minnesota electric rate case.

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

- Direct Testimony — July 2, 2014;
- Rebuttal Testimony — Aug. 26, 2014;
- Surrebuttal Testimony — Sept. 19, 2014;
- Hearing — Sept. 29-Oct. 3, 2014;
- Reply Brief — Nov. 21, 2014; and
- ALJ report — Dec. 31, 2014.

A final MPUC decision is anticipated in the first quarter of 2015.

NSP-Minnesota - 2012 Transmission Cost Recovery Rate Filing — In January 2012, the 2012 NSP-Minnesota TCR filing was submitted to the MPUC, requesting recovery of $29.6 million of transmission investment costs. As project costs have decreased and certain transmission project costs have been removed and included in base rates, the anticipated revenue requirement for 2012 was modified to approximately $22.9 million. In December 2013, the MPUC approved the 2012 TCR filing, with a few adjustments, for approximately $22.7 million.

NSP-Minnesota - 2013/14 Transmission Cost Recovery Rate Filing — In December 2013, the 2013/14 NSP-Minnesota TCR filing was filed with the MPUC, requesting recovery of $20.7 million of 2013 transmission investment costs and $37.3 million of 2014 transmission investment costs not previously included in electric base rates. An MPUC decision is anticipated in late 2014, with implementation of new rates soon after approval.

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

NSP-Minnesota plans to address recovery of incurred costs in rate cases for each of the NSP-Minnesota jurisdictions and to file a request with the FERC for approval to recover a portion of the costs from NSP-Wisconsin through the Interchange Agreement. NSP-Wisconsin plans to seek cost recovery in a future rate case. Based on the outcome of the December 2012 MPUC decision, EPU costs incurred to date were compared to the discounted value of the estimated future rate recovery based on past jurisdictional precedent, resulting in a $10.1 million pretax charge in December

2012 which is included in O&M expense for that year.

Pending and Recently Concluded Regulatory Proceedings — NDPSC

NSP-Minnesota – North Dakota 2013 Electric Rate Case — In December 2012, NSP-Minnesota filed a request with the NDPSC to increase annual retail electric rates approximately $16.9 million, or 9.25 percent. The rate filing was based on a 2013 FTY, a requested ROE of 10.6 percent, an electric rate base of approximately $377.6 million and an equity ratio of 52.56 percent. In January 2013, the NDPSC approved an interim electric increase of $14.7 million, effective Feb. 16, 2013, subject to refund.

Table of Contents

In August 2013, NSP-Minnesota filed rebuttal testimony revising the requested increase in retail electric rates to approximately $14.9 million, based on a revised ROE of 10.25 percent and incorporating updated information.

In December 2013, a comprehensive settlement agreement between NSP-Minnesota and the NDPSC Staff was filed for approval, proposing resolution to the rate case and resolution of various regulatory proceedings for wind and natural gas generating resources pending before the NDPSC. The settlement agreement provided for a four-year rate plan including a 5.0 percent annual increase in retail revenues in North Dakota, effective Feb. 16, 2013 through Dec. 31, 2015, with no increase in 2016. As filed, the estimated 2013 settlement impact was $11.6 million. On Feb. 18, 2014, NSP-Minnesota filed an amended settlement agreement revising the annual increase to 4.9 percent, effective Feb. 16, 2013 through Dec. 31, 2015, with no increase in 2016.

The table below reflects the amended settlement's 2013 impact.

(Millions of Dollars)	Amended Settlement Impact
Proposed 12 month settlement base rate increase	$9.0
Pre-effective period impact (Jan. 1, 2013 - Feb. 15, 2013)	(1.6)
Proposed settlement base rate increase	7.4
Retention of DOE settlement proceeds	3.9
Other, net	(0.3)
Amended settlement's 2013 impact	$11.0

Additional settlement terms include:

- An approval of two new rate rider tariff mechanisms to recover transmission and North Dakota renewable costs;
- An authorized ROE of 9.75, 10.0, 10.0 and 10.25 percent in 2013 through 2016, respectively;
- A 50 percent earnings sharing mechanism for amounts earned in excess of the authorized ROEs during the term of the settlement;
- The continued use of a 12 month CP demand allocator for certain rate base and operating expenses;
- A commitment to develop a generation cost allocation mechanism over the next 16 months that reflects North Dakota energy policy; providing for the exclusion of resources deemed inconsistent with North Dakota energy policy beginning in 2016 (such as certain Minnesota wind and biomass purchase power agreements) and reflecting replacement of those costs based on either system average costs or like resource costs (base load for base load generation, etc.) and recognizing the time needed to address complexity among multiple jurisdictions by providing that a plan for this mechanism be filed by June 2015;
- The commitment to construct up to 400 MW of thermal generation in North Dakota by 2036 subject to least-cost resource planning principles; and
- The retention of DOE settlement proceeds received in 2012, 2013 and expected in 2014.

A final NDPSC decision on the case is anticipated in the first quarter of 2014.

Recently Concluded Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota 2012 Electric Rate Case — In March 2013, NSP-Minnesota and the SDPUC Staff reached a settlement agreement that provides for a base rate increase of approximately $11.6 million and the implementation of a new rider. On Oct. 1, 2013, NSP-Minnesota filed its compliance report consistent with the settlement to recover the revenue requirement on the specific major capital additions and incremental property tax resulting in recovery of $8.7 million for 2014. In December 2013, the SDPUC approved recovery of $8.5 million, reflecting updates made during review of the compliance filing.

Electric, Purchased Gas and Resource Adjustment Clauses

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

Table of Contents

CIP expenses are recovered through base rates and a rider that is adjusted annually. In November 2013, the MPUC approved NSP-Minnesota's 2012 CIP electric financial incentives totaling $54.0 million, as well as NSP-Minnesota's proposed 2013 to 2014 electric CIP rider. In October 2013, the MPUC approved NSP-Minnesota's 2012 CIP natural gas financial incentive of $2.7 million, as well as NSP-Minnesota's proposed 2013 to 2014 natural gas CIP rider. NSP-Minnesota estimates 2014 recovery of $83.9 million of electric CIP expenses and $11.7 million of natural gas CIP expenses. This proposed recovery through the riders is in addition to an estimated $87.2 million and $3.1 million through electric and gas base rates, respectively.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

NSP-Wisconsin – Wisconsin 2014 Electric and Gas Rate Case — In May 2013, NSP-Wisconsin filed a request with the PSCW to increase rates for electric and natural gas service effective Jan. 1, 2014. NSP-Wisconsin requested an overall increase in annual electric rates of $40.0 million, or 6.5 percent, and an increase in natural gas rates of $4.7 million, or 3.8 percent. The electric rate increase included a $4.5 million adjustment related to proceeds from a nuclear settlement agreement with the DOE.

The rate filing was based on a 2014 FTY, an ROE of 10.4 percent, an equity ratio of 52.5 percent, and a forecasted average rate base of approximately $895.3 million for the electric utility and $89.8 million for the natural gas utility.

In October 2013, NSP-Wisconsin filed rebuttal testimony revising the requested electric rate increase to $34.3 million and natural gas rate increase to zero, based on a 10.4 percent ROE and other adjustments.

In December 2013, the PSCW approved an electric rate increase of approximately $19.5 million or 3.1 percent based on a 10.2 percent ROE and an equity ratio of 52.5 percent. The PSCW also approved cost deferrals of $4.1 million for interchange agreement amounts from NSP-Minnesota related to the Monticello EPU project until the MPUC completes its prudence review. The PSCW did not change rates for NSP-Wisconsin's natural gas utility. New electric rates went into effect on Jan. 1, 2014.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2013 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas rates by $48.5 million in 2013 with subsequent step increases of $9.9 million in 2014 and $12.1 million in 2015. The request was based on a 2013 FTY, a 10.5 percent ROE, a rate base of $1.3 billion and an equity ratio of 56 percent. PSCo requested an extension of its PSIA rider mechanism to collect the costs associated with its pipeline integrity efforts, including accelerated system renewal projects. PSCo estimated that the PSIA would increase by $26.8 million in 2014 with a subsequent step increase of $24.7 million in 2015 in addition to the proposed changes in base rate revenue. Interim rates, subject to refund, went into effect in August 2013.

In April 2013, several parties filed testimony. PSCo filed rebuttal testimony and revised its requested annual rate increase to $44.8 million for 2013, with subsequent step increases of $9.0 million for 2014 and $10.9 million for 2015, based on an ROE of 10.3 percent. This requested increase includes amounts to be transferred from the PSIA rider mechanism. The deficiency, based on an FTY, was $30.6 million.

In December 2013, the CPUC approved a natural gas base rate increase of approximately $15.8 million based on an ROE of 9.72 percent, a HTY with an end of year rate base and an equity ratio of 56 percent. As of Dec. 31, 2013, PSCo accrued revenue subject to refund of approximately $20.9 million.

While the CPUC rejected PSCo’s request of an FTY and multi-year rate plan, they made clear they supported the benefits that rate certainty brings to customers and PSCo. The CPUC did not reverse the ALJ’s failure to approve expansion and acceleration of PSCo’s pipeline integrity projects. However, the CPUC discussed the importance of pipeline integrity and safety matters and extended the PSIA recovery mechanism for one year to allow for PSCo to file an application for full consideration of all new projects and acceleration.

Table of Contents

The following table summarizes the CPUC decision:

(Millions of Dollars)	CPUC Decision
PSCo deficiency based on a FTY	$44.8
HTY adjustment	(5.4)
ROE and capital structure adjustments	(8.3)
Revenue adjustments	(1.4)
Other	(0.1)
Recommendation	29.6
Neutralize PSIA - base rate transfer	(13.8)
Incremental base revenue	$15.8

Rates and conforming changes made to the PSIA were effective Jan. 1, 2014.

PSCo – Colorado 2013 Steam Rate Case — In December 2012, PSCo filed a request to increase Colorado retail steam rates by $1.6 million in 2013 with subsequent step increases of $0.9 million in 2014 and $2.3 million in 2015. The request was based on a 2013 FTY, a 10.5 percent ROE, a rate base of $21 million for steam and an equity ratio of 56 percent.

In October 2013, PSCo, the CPUC Staff, the OCC and Colorado Energy Consumers filed a comprehensive settlement, which tied the outcome of the steam rate case to key issues to be decided in the natural gas rate case, including ROE and capital structure. The settlement allowed the filed rates to be effective on Jan. 1, 2014, subject to refund, resulting in a minimum 2014 annual rate increase of $1.2 million. The settlement also withdrew the rate relief request for 2015 without prejudice to PSCo seeking prospective rate relief at any time through the filing of a future steam case. In November 2013, the settlement became final. Final rates were implemented on Feb. 1, 2014.

PSCo – Annual Electric Earnings Test — An earnings sharing mechanism is used to apply prospective electric rate adjustments for earnings in the prior year over PSCo's authorized ROE threshold of 10 percent. In June 2013, PSCo entered into a comprehensive settlement of issues with all parties associated with the 2012 earnings test, resulting in a refund obligation of approximately $8.2 million to be refunded through June 2014. As of Dec. 31, 2013, PSCo has also recognized management's best estimate of an accrual for the 2013 test year.

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

ECA Prudence Review — In September 2013, the CPUC Staff requested that the 2012 annual ECA prudence review be set for hearing. The prudence review, as determined by the ALJ, will primarily consider if replacement power costs during the outage of jointly owned facilities were properly allocated between wholesale and retail customers.

2012 PSIA Report — In April 2013, PSCo filed its 2012 PSIA report. The OCC and CPUC Staff requested the CPUC set the matter for hearing to review in detail the information provided, including a review of the prudence of expenditures in 2012, and to develop standards for future filings. In July 2013, the CPUC approved the request and assigned the matter to an ALJ.

In January 2014, the CPUC Staff recommended a disallowance of $3.7 million of capital expenditures related to a pipeline replacement project and a disallowance related to an inspection program. Collectively, these represent approximately $0.6 million of disallowances related to 2012 revenue requirements. On Feb. 6, 2014, PSCo filed rebuttal testimony addressing the CPUC Staff’s recommended disallowances.

Table of Contents

Next steps in the procedural schedule are as follows:

- Evidentiary hearing — March 3 - March 7, 2014;
- Initial brief — March 28, 2014; and
- Reply brief — April 11, 2014.

Electric, Purchased Gas and Resource Adjustment Clauses

DSM and the DSMCA — The CPUC approved higher savings goals and a slightly higher financial incentive mechanism for PSCo's electric DSM energy efficiency programs starting in 2012. Savings goals are 356 GWh in 2013 and 384 GWh in 2014 with incentives awarded in the year following plan achievements. PSCo is able to earn an incentive on 11 percent of net economic benefits and a maximum annual incentive of $30 million.

The CPUC approved the PSCo electric and gas DSM budget of $115.5 million and $13.3 million, respectively, effective Jan. 1, 2013. Energy efficiency and DSM costs are recovered through a combination of the DSMCA riders and base rates. Electric DSMCA rates are designed to collect $26.8 million in 2013 with the remainder of the electric DSM expenditures collected through base rates. PSCo filed its 2014 DSM plan in July 2013 and reached a settlement with all but one party. Hearings were held in December 2013 seeking approval of a 2014 DSM electric budget of $87.8 million and a gas budget of $12.3 million. A decision by the ALJ is anticipated by the end of the first quarter of 2014. DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are trued-up in the following year.

REC Sharing — In May 2011, the CPUC determined that margin sharing on stand-alone REC transactions would be shared 20 percent to PSCo and 80 percent to customers and ultimately becoming 10 percent to PSCo and 90 percent to customers by 2014. The CPUC also approved a change to the treatment of hybrid REC trading margins (RECs that are bundled with energy) that allows the customers' share of the margins to be netted against the RESA regulatory asset balance.

In 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. PSCo credited the RESA regulatory asset balance $22 million and $46 million in 2013 and 2012, respectively. The cumulative credit to the RESA regulatory asset balance was $104.5 million and $82.8 million at Dec. 31, 2013 and Dec. 31, 2012, respectively. The credits include the customers' share of REC trading margins and the customers' share of carbon offset funds.

This sharing mechanism will be effective through 2014. The CPUC is then expecting to review the framework and evidence regarding actual deliveries before determining to continue the sharing mechanism.

ECA / RESA Adjustment — In July 2013, PSCo advised the CPUC that it had inadvertently allocated purchased power expense between the deferred accounts for the ECA and the RESA from 2010 to 2012. PSCo proposed to transfer from the RESA deferred account to the ECA deferred account approximately $26.2 million and to amortize the recovery of this amount over 12 months. In addition, interest of $4.4 million was accrued on the amount related to the RESA. In January 2014, the ALJ determined that the $26.2 million was prudently incurred and recommended full recovery through the ECA over a 12 month period with interest accrued at the ECA interest rate. The difference between the RESA interest rate and the ECA interest rate is a decrease of approximately 7.4 percent, or $4.3 million.

Pending and Recently Concluded Regulatory Proceedings — FERC

PSCo – Production Formula Rate ROE Complaint — In August 2013, PSCo's wholesale production customers filed a complaint with the FERC, and requested it reduce the stated ROEs ranging from 10.1 percent through 10.4 percent to 9.04 percent in the PSCo power sales formula rates effective Sept. 1, 2013, which could reduce revenues approximately $2 million per year prospectively. The matter is currently pending the FERC's action.

Table of Contents

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission formula rates from a HTY formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's wholesale transmission and ancillary services revenue by approximately $2.0 million annually. Various transmission customers taking service under the tariff protested the filing. In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to November 2012, subject to refund, and setting the case for settlement judge or hearing procedures.

In June 2012, several wholesale customers filed a complaint with the FERC seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012. If implemented, the ROE reduction would reduce PSCo transmission and ancillary rate revenues by approximately $1.8 million annually. In October 2012, the FERC issued an order accepting the complaint, consolidating the complaint with the April 2012 formula rate change filing, establishing a refund effective date of July 1, 2012, and setting the complaint for settlement judge and hearing procedures.

In October 2013, PSCo and the wholesale customers filed a partial settlement that would resolve all issues related to the April 2012 transmission rate filing and June 2012 complaint other than ROE. The settlement is not expected to materially increase 2013 transmission revenues. In December 2013, the FERC approved the partial settlement. The ROE issue is now in an evidentiary hearing process. Initial testimony was filed in December 2013. PSCo filed testimony supporting the current ROE of 10.25 percent, while customers filed testimony recommending an ROE of 9.07 percent for the period July 2012 to November 2012, and an ROE of 8.92 percent thereafter. The case is scheduled for a hearing before an ALJ in May 2014, with the ALJ recommended decision by September 2014.

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

SPS – Texas 2014 Electric Rate Case — On Jan. 7, 2014, SPS filed a retail electric rate case in Texas with each of its Texas municipalities and the PUCT for a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflects a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the TCRF to zero when the final base rates become effective, as shown in the following table:

(Millions of Dollars)	SPS Request	
Base rate increase	$81.5	
Resetting TCRF	(12.9	)
Credit to customers for gain on sale to Lubbock moved to a rider	(4.9	)
Net increase in base revenue	63.7	
Fuel clause offsets	(11.0	)
Retail customer net bill impact	$52.7	

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

The PUCT has suspended SPS' proposed rates through Oct. 31, 2014. If the PUCT has not issued a final order by July 11, 2014, then SPS' current rates will not change, but the final rates will be made effective retroactive to July 12, 2014.

Next steps in the procedural schedule are as follows:

- Intervenor testimony — May 22, 2014;
- PUCT Staff testimony — May 29, 2014;
- Cross-rebuttal testimony — June 12, 2014;
- Rebuttal testimony — June 16, 2014;
- Evidentiary hearing — June 25, 2014; and
- A PUCT decision and implementation of final rates are anticipated in the third quarter of 2014.

Table of Contents

SPS – Texas 2012 Electric Rate Case — In November 2012, SPS filed an electric rate case in Texas with the PUCT for an increase in annual revenue of approximately $90.2 million. The rate filing is based on a historic 12 month test year ended June 30, 2012 (adjusted for known and measurable changes), a requested ROE of 10.65 percent, an electric rate base of $1.15 billion and an equity ratio of 52 percent. In June 2013, the PUCT approved a settlement agreement in which SPS' base rate increased by $37 million, effective May 1, 2013 and by an additional $13.8 million on Sept. 1, 2013.

Electric, Purchased Gas and Resource Adjustment Clauses

TCRF Rider — In November 2013, SPS filed with the PUCT to implement the TCRF for Texas retail customers. The requested increase in revenues is $13 million. The PUCT issued an order allowing the TCRF to go into effect on an interim basis effective Jan. 1, 2014.

Next steps in the procedural schedule are as follows:

- Intervenor testimony — April 17, 2014;
- Rebuttal testimony — May 6, 2014; and
- Evidentiary hearings — May 15 - May 16, 2014.

Pending Regulatory Proceedings — NMPRC

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the NMPRC for an increase in annual revenue of approximately $45.9 million effective in 2014. The rate filing is based on a 2014 FTY, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent. In June 2013, SPS revised its requested rate increase to $43.3 million.

In August 2013, the NMPRC Staff (Staff), the NMAG, the Federal Executive Agencies, the Coalition of Clean Affordable Energy, Occidental Permian, Ltd. and New Mexico Gas Company filed testimony.

The following table summarizes certain parties' recommendations from SPS' revised request:

(Millions of Dollars)	Staff Testimony August 2013	NMAG Testimony August 2013
SPS revised request	$43.3	$43.3
Rate rider for renewable energy costs [(a)]	(14.5)	(8.5)
Present revenues (sales growth and weather)	(4.4)	(6.4)
ROE (9.8 percent and 8.63 percent, respectively)	(3.2)	(8.1)
Capital structure	(1.5)	(1.1)
Employee benefits	(2.8)	(1.8)
Reduced recovery for payroll expense	(0.1)	(0.1)
Gain on sale of transmission assets	—	(1.7)
Fuel clause revenue	6.0	—
Other, net	(5.0)	(6.6)
Recommended rate increase	$17.8	$9.0
Means of recovery:		
Base revenue	$8.8	$(6.0)
Rider revenue	7.3	13.3
Fuel cost adjustment revenue	1.7	1.7
	$17.8	$9.0

(a) Adjustments represent recommended deferrals, extended amortizations and moving costs from rider to fuel in base rates.

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

Table of Contents

In January 2014, the hearing examiner released her recommended decision. SPS estimates the recommendation reduces the requested rate increase by approximately $6.2 million, resulting in a base revenue increase of $14.7 million. The recommendation proposes an ROE of 9.73 percent, an equity ratio of 53.89 percent, an FTY with certain adjustments and excludes certain employee benefits and other costs. In February 2014, the hearing examiner released a supplemental recommended decision proposing the approval of the requested $12.1 million renewable energy rider revenue recovery. Parties have filed exceptions to the hearing examiner's recommendations. An NMPRC decision and final rates are expected to be effective in the second quarter of 2014.

Pending and Recently Concluded Regulatory Proceedings — FERC

SPS 2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order on rehearing related to a 2004 Complaint case brought by Golden Spread Electric Cooperative, Inc. (Golden Spread), a wholesale cooperative customer, and PNM and an Order on Initial Decision in a subsequent 2006 rate case filed by SPS.

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

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

The pre-tax impact to 2013 earnings from these orders is approximately $36 million. Pending the timing and resolution of this matter, the annual impact to revenues through 2014 could be up to $6 million and decreasing to $4 million on June 1, 2015.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling.

In October 2013, the FERC issued orders further considering the requests for rehearing. These matters are currently pending the FERC's action. If unsuccessful in its rehearing request, SPS will have the opportunity to file rate cases with the FERC and its retail jurisdictions seeking to change all customers to a 3CP allocation method.

SPS Wholesale Rate Complaint — In April 2012, Golden Spread filed a rate complaint alleging that the base ROE included in the SPS production formula rate of 10.25 percent, and the SPS transmission base formula rate ROE of 10.77 percent, are unjust and unreasonable. Golden Spread alleged that the appropriate base ROE is 9.15 percent, or an annual difference of approximately $3.3 million. An additional 50 basis point incentive is added to the base ROE for the transmission formula rate for SPS' participation in the SPP RTO. Golden Spread is not contesting this transmission incentive. The FERC has taken no action on this complaint. If granted, the complaint could reduce SPS revenues approximately $3.1 million per year prospectively from the effective date established by the FERC.

Sale of Texas Transmission Assets — In March 2013, SPS reached an agreement to sell certain segments of SPS' transmission lines and two related substations to Sharyland. In 2013, SPS received all necessary regulatory approvals for the transaction. On Dec. 30, 2013, SPS received $37.1 million and recognized a pre-tax gain of $13.6 million. The gain is reflected in the consolidated statement of income as a reduction to O&M expenses. Regulatory liabilities were recorded for jurisdictional gain sharing of $7.2 million.

Table of Contents

13. Commitments and Contingencies

Commitments

Capital Commitments — Xcel Energy has made commitments in connection with a portion of its projected capital expenditures. Xcel Energy's capital commitments primarily relate to the following major projects:

Southeast New Mexico Transmission Development — SPS is developing a transmission expansion plan for southeastern New Mexico. The SPP, with input from SPS, is conducting a High Priority Incremental Load Study to review oil and natural gas load additions in several areas, including southeastern New Mexico. A final report is expected by SPP in April 2014. SPS has started right-of-way work on four projects for which NTCs are anticipated from SPP in early 2014.

CapX2020 — CapX2020 is an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest, including the NSP System that has proposed several groups of transmission projects to be completed by 2020. Group 1 project investments consist of four transmission lines. Major construction began in 2010 on the Group 1 transmission lines with an expected completion date in 2015. NSP System's investment depends on the routes and configurations approved by affected state commissions and on the allocation of costs borne by other participating utilities in the upper Midwest.

CACJA — The CACJA required PSCo to file a plan to reduce annual emissions of NOx by at least 70 to 80 percent or greater from 2008 levels by 2017 from its coal fired generation resources. In September 2012, the EPA formally approved the Colorado SIP for regional haze, including resource planning changes that include early coal-fueled plant retirements, fuel switching and SCR installation.

PSCo Gas Transmission Integrity Management Programs – PSCo is proactively identifying and addressing the safety and reliability of natural gas transmission pipelines. The pipeline integrity efforts include system renewal projects and increased maintenance.

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

SPS Transmission NTC — SPS has accepted NTCs for several hundred miles of transmission line and related substation projects based on needs identified through SPP's various planning processes, including those associated with economics, reliability, generator interconnection or the load addition processes. A major project committed to is the TUCO to Woodward District Extra High Voltage Interchange, a 345 KV transmission line. This line connects the TUCO substation near Lubbock, Texas with the OGE substation in Woodward, Okla. The PUCT approved SPS' CCN to build the line in 2012. It is anticipated to be complete in 2014.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2014 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for Xcel Energy under these contracts as of Dec. 31, 2013 are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation

2014	$947.6	$128.8	$492.8	$272.3
2015	770.7	79.9	234.4	266.4
2016	500.2	121.5	232.0	207.5
2017	221.3	127.5	225.4	164.2
2018	73.2	69.4	278.4	106.6
Thereafter	428.6	697.6	1,211.3	1,214.2
Total	$2,941.6	$1,224.7	$2,674.3	$2,231.2

Table of Contents

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. Xcel Energy's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2033 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $217.0 million, $261.9 million and $325.3 million in 2013, 2012 and 2011, respectively. At Dec. 31, 2013, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy [a]
2014	$254.2	$121.9
2015	254.5	120.5
2016	215.5	100.2
2017	186.1	90.4
2018	141.1	93.2
Thereafter	571.3	866.7
Total	$1,622.7	$1,392.9

[a] Excludes contingent energy payments for renewable PPAs.

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

Leases — Xcel Energy leases a variety of equipment and facilities used in the normal course of business. Three of these leases qualify as capital leases and are accounted for accordingly. The assets and liabilities at the inception of a capital lease are recorded at the lower of fair market value or the present value of future lease payments and are amortized over the term of the contract.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy Inc. has a 50 percent ownership interest in WYCO. WYCO leases the facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under a service arrangement.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had $144.2 million and $148.7 million of capital lease obligations recorded for the arrangement as of Dec. 31, 2013 and 2012, respectively. Xcel Energy Inc. eliminates 50 percent of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital leases as cost of natural gas sold and transported on the consolidated statements of income. Total amortization expenses under capital lease assets were approximately $6.3 million, $5.7 million and $3.2 million for 2013, 2012 and 2011, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	2013	2012
Storage, leaseholds and rights	$200.5	$200.5
Gas pipeline	20.7	20.7
Property held under capital lease	221.2	221.2
Accumulated depreciation	(41.8)	(35.5)
Total property held under capital leases, net	$179.4	$185.7

Table of Contents

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately $242.1 million, $217.8 million and $204.8 million for 2013, 2012 and 2011, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of $197.7 million, $174.4 million and $160.5 million in 2013, 2012 and 2011, respectively, recorded to electric fuel and purchased power expenses.

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

Future commitments under operating and capital leases are:

(Millions of Dollars)	Operating Leases	PPA Operating Leases [a] [b]	Total Operating Leases	Capital Leases
2014	$26.5	$214.2	$240.7	$18.0
2015	25.4	207.4	232.8	17.8
2016	22.4	197.0	219.4	17.1
2017	17.2	192.7	209.9	15.0
2018	16.1	194.4	210.5	14.7
Thereafter	143.6	1,771.9	1,915.5	289.1
Total minimum obligation				371.7
Interest component of obligation				(264.3)
Present value of minimum obligation				$107.4 [c]

[a] Amounts do not include PPAs accounted for as executory contracts.
[b] PPA operating leases contractually expire through 2033.
[c] Future commitments exclude certain amounts related to Xcel Energy's 50 percent ownership interest in WYCO.

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

PPAs —Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the associated independent power producing entity.

Xcel Energy has determined that certain independent power producing entities are variable interest entities. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is in the future, required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The Xcel Energy utility subsidiaries had approximately 3,338 MW and 3,324 MW of capacity under long-term PPAs as of Dec. 31, 2013, and 2012, respectively, with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2033.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO under contracts for those facilities that expire in 2016 and 2017, respectively. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS’ requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

No significant financial support has been, or is in the future, required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs. SPS has determined that TUCO is a variable interest entity. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. These limited partnerships are designed to qualify for low-income housing tax credits, and Eloigne and NSP-Wisconsin generally receive a larger allocation of the tax credits than the general partners at inception of the arrangements. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne, NSP-Wisconsin and the general partner of each limited partnership, and Xcel Energy's risk of loss is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is in the future, required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin. Mortgage-backed debt typically comprises the majority of the financing at inception of each limited partnership and is paid over the life of the limited partnership arrangement. Obligations of the limited partnerships are generally secured by the housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy Inc. or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy Inc. or its subsidiaries.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	Dec. 31, 2013	Dec. 31, 2012
Current assets	$7,982	$3,380
Property, plant and equipment, net	65,451	72,489
Other noncurrent assets	1,654	6,044
Total assets	$75,087	$81,913
Current liabilities	$11,388	$8,458
Mortgages and other long-term debt payable	38,049	37,720
Other noncurrent liabilities	707	7,678
Total liabilities	$50,144	$53,856

Technology Agreements — Xcel Energy has a contract that extends through June 2019 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50 percent of the contract value for early termination. Xcel Energy capitalized or expensed $90.3 million, $86.5 million and $93.6 million associated with the IBM contract in 2013, 2012, and 2011, respectively.

Xcel Energy's contract with Accenture for information technology services extends through Jan. 2017. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $23.7 million, $18.3 million and $15.2 million associated with the Accenture contract in 2013, 2012 and 2011, respectively.

Table of Contents

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2014	$35.5	$8.9
2015	32.2	8.8
2016	31.5	8.8
2017	31.6	—
2018	31.1	—
Thereafter	15.5	—

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Dec. 31, 2013 and 2012, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding as of Dec. 31, 2013:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of customer loans for the Farm Rewiring Program [(a)]	NSP-Wisconsin	$1.0	$0.3	[(e)]
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases [(b)]	Xcel Energy Inc.	9.2	—	[(f)]
Guarantee of residual value of assets under the BTM Capital Corporation Equipment Leasing Agreement [(c)]	NSP-Minnesota	9.2	—	[(g)]
Total guarantees issued		$19.4	$0.3	
Guarantee performance and payment of surety bonds for Xcel Energy Inc. and its subsidiaries [(d)]	Xcel Energy Inc.	$32.1	[(i)]	[(h)]

(a) The term of this guarantee expires in 2017, which is the final scheduled repayment date for the loans. As of Dec. 31, 2013, no claims had been made by the lender.

(b) The term of this guarantee expires in 2017 when the associated leases expire.

(c) The terms of these guarantees expire in 2014 and 2015 when the associated leases expire.

(d) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(e) The debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Nonperformance and/or nonpayment.

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

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

(i) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

In connection with the sale of certain Texas electric transmission assets to Sharyland, SPS agreed to indemnify the purchaser for losses arising out of any breach of the representations, warranties and covenants under the related asset purchase agreement and for losses arising out of certain other matters, including pre-closing liabilities. SPS' indemnification obligation is capped at $37.1 million, in the aggregate. The indemnification provisions for most representations and warranties expire in December 2014. The remaining representations and warranties, which relate to due organization and transaction authorization, survive indefinitely. SPS has recorded a $0.4 million liability related to this indemnity.

Table of Contents

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

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

Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by Xcel Energy Inc.'s subsidiaries or their predecessors, or other entities; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to be a PRP that sent hazardous materials and wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

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

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

In October 2012, a settlement among the EPA, the WDNR, the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin was approved by the U.S. District Court for the Western District of Wisconsin. This settlement resolves claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the settlement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. The settlement reflects a cost estimate for the clean up of the Phase I Project Area of $40 million. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. As part of the settlement, NSP-Wisconsin has conveyed approximately 1,390 acres of land to the State of Wisconsin and tribal trustees. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues.

Table of Contents

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments and what remedy will be implemented at the site to address the Sediments. In August and September 2013, NSP-Wisconsin performed field studies in the Sediments to gather more data about site conditions. The data from that investigation was received and reported to the EPA at the end of 2013. It is NSP-Wisconsin's view that this data demonstrates the Hybrid Remedy is not safe or feasible to implement. The EPA's ROD for the Ashland site includes estimates that the cost of the Hybrid Remedy is between $63 million and $77 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower. Also, in September 2013, the EPA requested NSP-Wisconsin consider re-submitting another proposal to perform a Wet Dredge pilot study for a portion of the Sediments. NSP-Wisconsin previously submitted a proposal for a Wet Dredge pilot study in 2011. In November 2013, NSP-Wisconsin submitted a revised Wet Dredge pilot study work plan proposal to the EPA. NSP-Wisconsin is in the process of negotiating a final pilot study work plan for possible implementation in late summer or early fall of 2014.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. Trial for this matter is scheduled for April 2015. Negotiations between the EPA, NSP-Wisconsin and several of the other PRPs regarding the PRPs' fair share of the cleanup costs for the Ashland site are also ongoing.

At Dec. 31, 2013 and 2012, NSP-Wisconsin had recorded a liability of $104.6 million and $103.7 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $25.2 million and $20.1 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin retail rate case process. Under an existing PSCW policy, utilities have recovered remediation costs for MGPs in natural gas rates, amortized over a four- to six-year period. The PSCW historically has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation.

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

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where hazardous or other regulated materials may have been deposited. Xcel Energy has identified seven sites across all of its service territories, where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2014. Xcel Energy had accrued a total of $5.1 million and $3.0 million for all of these sites at Dec. 31, 2013 and 2012, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Table of Contents

Environmental Requirements

Water and waste

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

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In June 2013, the EPA published a proposed ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. Refuse derived fuel, biomass and other alternatively fueled power plants are not addressed by the proposed revisions. The proposed rule identifies four potential regulatory options and invites comments on those regulatory approaches. The options differ in the number of waste streams covered, size of the units controlled and stringency of controls. It is not yet known when the EPA will issue a finalized rule. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017 but no later than July 2022. The impact of this rule on Xcel Energy is uncertain at this time.

Federal CWA Section 316 (b) — 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. In 2011, the EPA published the proposed rule that sets standards for minimization of aquatic species impingement, but leaves entrainment reduction requirements at the discretion of the permit writer and the regional EPA office. A final rule is anticipated in April 2014. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the uncertainty of the final regulatory requirements.

NSP-Minnesota submitted its Black Dog CWA compliance plan for the MPCA's review and approval in 2010. The MPCA is currently reviewing the proposal in consultation with the EPA.

Proposed Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of hazardous waste. In 2010, the EPA published a proposed rule on whether to regulate coal combustion byproducts (coal ash) as hazardous or nonhazardous waste. Coal ash is currently exempt from hazardous waste regulation. Xcel Energy's costs for the management and disposal of coal ash would significantly increase and the beneficial reuse of coal ash would be negatively impacted if the EPA ultimately issues a rule under which coal ash is regulated as hazardous waste. The EPA has entered into a consent decree to act on final regulations by December 2014. The timing, scope and potential cost of any final rule that might be implemented are not determinable at this time.

Air

EPA GHG Regulation — In 2009, the EPA issued its "endangerment" finding that GHG emissions pose a threat to public health and welfare. This finding required the EPA to adopt GHG emission standards for mobile sources. In 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which are applicable to the construction of new power plants or power plant modifications that increase emissions above a certain threshold. These rules were upheld on appeal to the D.C. Circuit. The U.S. Supreme Court has granted review on one issue related to these rules, specifically whether the EPA's regulation of GHG emissions from mobile sources triggered, by operation of law, new source review permitting requirements for stationary sources, which was the EPA's basis for adopting the 2011 permitting rules. The Court is scheduled to hear arguments in February 2014. A ruling is anticipated by June 2014. Xcel Energy is unable to determine the cost of compliance with these new EPA requirements as it is not clear whether these requirements will apply to future changes at Xcel Energy's power plants.

GHG Emission Standard for Existing Sources and NSPS Proposal — In June 2013, President Obama issued a memorandum directing the EPA to develop GHG emission standards for existing power plants. The memorandum anticipates the EPA will issue a proposed GHG emission standard for existing power plants in June 2014. It is not possible to evaluate the impact of existing source standards until the upcoming proposal and final requirements are known.

Table of Contents

In January 2014, the EPA re-proposed a GHG NSPS for newly constructed power plants which seeks to establish CO_2 emission rates for coal-fired power plants that reflect emission reductions using partial carbon capture and storage technology (CCS). The EPA's proposed CO_2 emission limits for gas-fired power plants reflect emissions levels from combined cycle technology with no CCS. The EPA continues to propose that the NSPS not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. It is not possible to evaluate the impact of the re-proposed NSPS until its final requirements are known.

CSAPR — In 2011, the EPA issued the CSAPR to address 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. For Xcel Energy, the rule would have applied in Minnesota, Wisconsin and Texas. The CSAPR would have set more stringent requirements than the proposed Clean Air Transport Rule and would have required plants in Texas to reduce their SO_2 and annual NOx emissions. The rule also would have created an emissions trading program.

In August 2012, the D.C. Circuit vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated that the EPA must continue administering the CAIR pending adoption of a valid replacement. In December 2013, the U.S. Supreme Court heard oral arguments on the D.C. Circuit's 2012 decision to vacate the CSAPR. A decision is anticipated by June 2014. It is not yet known whether the D.C. Circuit's decision will be upheld, or how the EPA might approach a replacement rule. Therefore, it is not known what requirements may be imposed in the future.

As the EPA continues administering the CAIR while the CSAPR or a replacement rule is pending, Xcel Energy expects to comply with the CAIR as described below.

CAIR — In 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The CAIR applies to Texas and Wisconsin. The CAIR does not currently apply to Minnesota.

Under the CAIR's cap and trade structure, companies can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. NSP-Wisconsin purchased allowances in 2012 and 2013 and plans to continue to purchase allowances in 2014 to comply with the CAIR. In the SPS region, installation of low-NOx combustion control technology was completed in 2012 on Tolk Unit 1. SPS plans to install the same combustion control technology on Tolk Unit 2 in the second quarter of 2014. These installations will reduce or eliminate SPS' need to purchase NOx emission allowances. SPS had sufficient SO_2 allowances to comply with the CAIR in 2013 and has sufficient allowances for 2014. At Dec. 31, 2013, the estimated annual CAIR NOx allowance cost for Xcel Energy did not have a material impact on the results of operations, financial position or cash flows.

EGU Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective in April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. Xcel Energy expects to comply with the EGU MATS rule through a combination of mercury and other emission control projects. Xcel Energy believes EGU MATS costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

Minnesota Mercury Legislation — NSP-Minnesota installed sorbent control systems at the Sherco Unit 3 and A.S. King generating plants and has obtained MPUC approval to install mercury controls on Sherco Units 1 and 2 by the end of 2014. NSP-Minnesota projects installation costs of $12.0 million for the mercury controls on the units and believes these costs will be recoverable through regulatory mechanisms.

Industrial Boiler (IB) MACT Rules — In 2011, the EPA finalized IB MACT rules to regulate boilers and process heaters fueled with coal, biomass and liquid fuels, which would apply to NSP-Wisconsin's Bay Front Units 1 and 2. The capital cost to install controls to meet the requirements in the final reconsidered rule is anticipated to be $17.2 million in total and is targeted for completion in 2014.

Regional Haze Rules — In 2005, the EPA amended the BART requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In their first regional haze SIPs, Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

Table of Contents

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the CACJA emission reduction plan as satisfying regional haze requirements for the facilities included in the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at the Hayden and Pawnee plants are projected to cost $359.5 million and are expected to be installed between 2014 and 2017. PSCo anticipates these costs will be fully recoverable in rates.

The Colorado Mining Association (CMA) challenged the Colorado SIP in Colorado District Court. The District Court dismissed the CMA's challenge in 2012, and the Colorado Court of Appeals upheld the District Court's decision in November 2013. The CMA did not petition for review by the Colorado Supreme Court, thus ending the case.

In March 2013, WildEarth Guardians petitioned the U.S. Court of Appeals for the 10th Circuit to review the EPA's decision approving the Colorado SIP. WildEarth Guardians has stated it will challenge the BART determination made for Comanche Units 1 and 2. In comments before the EPA, WildEarth Guardians urged that current emission limitations be made more stringent or that SCR be added to the units. PSCo intervened in the case. The 10th Circuit is scheduled to hear argument in November 2014, following completion of the briefs in August 2014.

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

NSP-Minnesota

In 2009, the MPCA approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The combustion controls have been installed and the scrubber upgrades, to be completed by January 2015, are underway. These emission controls are projected to cost approximately $50 million, of which $40.3 million has already been spent. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

After the CSAPR was adopted in 2011, the MPCA supplemented its Minnesota SIP, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, the EPA approved the Minnesota SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2 as strengthening the Minnesota SIP, but avoided characterizing them as BART limits.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit. NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Court ordered this case to be held in abeyance until the U.S. Supreme Court decides on the CSAPR. If this litigation results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. It is not yet known how the U.S. Supreme Court's review of the CSAPR may impact the EPA's approval of the Texas SIP.

Reasonably Attributable Visibility Impairment (RAVI) — Additional visibility rules relate to a program called the RAVI program. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA has stated it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program. It is not yet known when the EPA will publish a proposal under RAVI or what that proposal will entail.

Table of Contents

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club. The lawsuit alleges the EPA has failed to perform a nondiscretionary duty to determine BART for Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. The Court denied NSP-Minnesota's motion to intervene in July 2013. NSP-Minnesota appealed this decision to the U.S. Court of Appeals for the Eighth Circuit. Oral arguments have been scheduled for March 2014.

Revisions to National Ambient Air Quality Standards (NAAQS) for PM — In December 2012, the EPA lowered the primary health-based NAAQS for annual average fine PM and retained the current daily standard for fine PM. In areas where Xcel Energy operates power plants, current monitored air concentrations are below the level of the final annual primary standard. The EPA is expected to designate non-compliant locations by December 2014. States would then study the sources of the nonattainment and make emission reduction plans to attain the standards. It is not possible to evaluate the impact of this regulation further until the final designations have been made.

PSCo NOV — In 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Generating Station in Colorado. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid to late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

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

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas production, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. This asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination dates on the ARO recognition for ash-containment facilities at steam plants was the in-service dates of the various facilities. NSP-Minnesota and PSCo have also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract, with the origination dates being the in-service date of the various facilities.

Xcel Energy has recognized an ARO for the retirement costs of natural gas mains at NSP-Minnesota, NSP-Wisconsin and PSCo and an ARO for the retirement of above ground gas storage facilities at PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings. These assets have numerous in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

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

Table of Contents

A reconciliation of Xcel Energy's AROs is shown in the tables below for the years ended Dec. 31, 2013 and 2012:

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

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.6 billion as of Dec. 31, 2013, consisting of external investment funds.

In 2013, Xcel Energy revised asbestos, ash containment facilities, radiation sources, miscellaneous electric production, electric transmission and distribution, natural gas transmission and distribution and general AROs due to revised estimated cash flows. Additionally, in 2013, an ARO was recorded to reflect the expected costs with the retirement of certain gas gathering facilities at PSCo and AROs were settled for the asbestos abatement at the Cameo and Riverview generating facilities at PSCo and SPS, respectively.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2012	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2012
Electric plant						
Nuclear production decommissioning	$1,482,741	$—	$—	$75,301	$(11,684)	$1,546,358
Steam and other production ash containment	41,278	—	—	1,614	18,843	61,735
Steam and other production asbestos	54,342	1,962	(9,372)	3,417	(4,888)	45,461
Wind production	40,515	2,928	—	2,068	(9,647)	35,864
Electric distribution	27,592	—	—	1,000	(4,442)	24,150
Other	2,390	—	—	92	670	3,152
Natural gas plant						
Gas transmission and distribution	1,201	—	—	73	(16)	1,258
Common and other property						
Common general plant asbestos	1,135	—	—	62	—	1,197
Common miscellaneous	599	—	—	22	—	621
Total liability	$1,651,793	$4,890	$(9,372)	$83,649	$(11,164)	$1,719,796

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was $1.5 billion as of Dec. 31, 2012, consisting of external investment funds.

In 2012, revisions were made for nuclear decommissioning, asbestos, ash-containment facilities, wind facilities and electric transmission and distribution AROs due to revised estimated cash flows.

Indeterminate AROs — PSCo has underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined; therefore, an ARO has not been recorded.

Table of Contents

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

The accumulated balances by entity were as follows at Dec. 31:

(Millions of Dollars)	2013	2012
NSP-Minnesota	$378	$377
NSP-Wisconsin	116	114
PSCo	359	365
SPS	53	67
Total Xcel Energy	$906	$923

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $13.6 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $16.1 million for business interruption insurance and $40.2 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Table of Contents

Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. NSP-Minnesota recorded a $101 million deposit in the first quarter of 2011, which was collected in April 2011. In May 2011, NSP-Minnesota filed a declaratory judgment action in the U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements. enXco also filed a separate lawsuit in the same court seeking approximately $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit. In October 2012, NSP-Minnesota filed a motion for summary judgment. In April 2013, the U.S. District Court granted NSP-Minnesota's motion and entered judgment in its favor. In April 2013, enXco filed a notice of appeal to the Eighth Circuit. It is uncertain when the Eighth Circuit will decide this appeal. Although Xcel Energy believes the likelihood of loss is remote based on existing case law and the U.S. District Court's April 2013 decision, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. No accrual has been recorded for this matter.

Exelon Wind (formerly John Deere Wind) Complaint — Several lawsuits in Texas state and federal courts and regulatory proceedings have arisen out of a dispute concerning SPS' payments for energy and capacity produced from the Exelon Wind subsidiaries' projects. There are two main areas of dispute. First, Exelon Wind claims that it established legally enforceable obligations (LEOs) for each of its 12 wind facilities in 2005 through 2008 that require SPS to buy power based on SPS' forecasted avoided cost as determined in 2005 through 2008. Although SPS has refused to accept Exelon Wind's LEOs, SPS accepts that it must take energy from Exelon Wind under SPS' PUCT-approved QF Tariff. Second, Exelon Wind has raised various challenges to SPS' PUCT-approved QF Tariff, which became effective in August 2010. The state and federal lawsuits and regulatory proceedings are in various stages of litigation, including a pending appeal by SPS in the Fifth Circuit Court of Appeals. SPS believes the likelihood of loss in these lawsuits and proceedings is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

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

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

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

Table of Contents

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

A hearing in this case was held before a FERC ALJ and concluded in October 2013. The matter is presently being briefed, and the ALJ is expected to issue an initial decision on or before March 18, 2014.

Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately $28 million excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors. First, not withstanding PSCo's view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the FERC's standard has been challenged on appeal to the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Fru-Con Construction Corporation (Fru-Con) vs. Utility Engineering Corporation (UE) et al. — In December 2001, a former wholly owned subsidiary of SPS and power plant design services company, UE, was engaged by the Sacramento Municipal Utility District (SMUD) to furnish design services for a natural gas-fired, combined-cycle power plant to be constructed by Fru-Con. In March 2005, Fru-Con commenced a lawsuit against UE and SMUD for damages allegedly suffered during the construction of the plant. In April 2005, Zachry Group (Zachry) purchased UE from Xcel Energy. As this lawsuit commenced prior to the sale of UE to Zachry, Xcel Energy agreed to indemnify Zachry for damages related to this case up to $17.5 million. In October 2013, the lawsuit was dismissed. Xcel Energy's obligation to indemnify Zachry for damages related to the sale expired upon final resolution of this case, which brings this litigation to a close.

Nuclear Power Operations and Waste Disposal

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE's failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the court awarded NSP-Minnesota $116.5 million in damages. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, estimated to be an additional $100 million. In January 2014, the United States proposed, and NSP-Minnesota accepted, an extension to the settlement agreement which will allow NSP-Minnesota to recover spent fuel storage costs through 2016. The extension does not address costs for used fuel storage after 2016; such costs could be the subject of future litigation. NSP-Minnesota received the initial $100 million payment in August 2011, the second installment of $18.6 million in March 2012, the third installment of $20.7 million in October 2012, and the fourth installment of $42.6 million in November 2013.

Amounts received from the installments were subsequently credited to customers, except for approved reductions such as legal costs, customer credits still in process at Dec. 31, 2013, and amounts set aside to be credited through another regulatory mechanism.

Other Contingencies

See Note 12 for further discussion.

Table of Contents

14. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. In January 2014, the DOE sent its court mandated proposal to adjust the current fee to zero. The Nuclear Waste Policy Act provides that a proposal by the Secretary of Energy to adjust the fee shall be effective after a period of 90 days of continuous session unless either House of Congress adopts a resolution disapproving the Secretary's proposed adjustment.

Fuel expense includes the DOE fuel disposal assessments of approximately $10 million in 2013, $12 million in 2012 and $11 million in 2011. In total, NSP-Minnesota had paid approximately $444.8 million to the DOE through Dec. 31, 2013. See Note 13 — Nuclear Waste Disposal Litigation for further discussion.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity currently authorized by the NRC and the MPUC will allow NSP-Minnesota to continue operation of its Prairie Island nuclear plant until the end of its renewed licenses terms in 2033 for Unit 1 and 2034 for Unit 2 and its Monticello nuclear plant until the end of its renewed operating license in 2030. Other alternatives for spent fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

Regulatory Plant Decommissioning Recovery — Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through at least 2091, assuming the prompt dismantlement method. NSP-Minnesota is currently recording the costs for decommissioning over the MPUC-approved cost-recovery period.

Monticello received its initial operating license in 1970 and began commercial operation in 1971. With its renewed operating license and CON for spent fuel capacity to support 20 years of extended operation, Monticello can operate until 2030. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC in 2007. The Monticello dry-cask storage facility currently stores 15 of the 30 canisters authorized by the MPUC.

Prairie Island Units 1 and 2 received their initial operating license and began commercial operations in 1973 and 1974. With its renewed operating license from the NRC, Prairie Island Units 1 and 2 can operate until 2033 and 2034, respectively. The MPUC approved depreciation life for Prairie Island is consistent with the remaining life of the NRC approved operating license. The Prairie Island dry-cask storage facility currently stores 35 of the 64 casks authorized by the MPUC.

NSP-Minnesota previously recorded annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding consistent with cost-recovery in utility customer rates. Cost studies quantify decommissioning costs in current dollars. This study presumed that costs will escalate in the future at a rate of 3.63 percent per year during operations and radiological portion of decommissioning and 2.63 percent during the independent spent fuel storage installation and site restoration portion of decommissioning. The total estimated decommissioning costs that will ultimately be paid, net of income earned by the external decommissioning trust fund, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is an after-tax return between 4.57 percent and 5.53 percent, depending on production unit and time frame for external funding. The net unrealized gain or loss on nuclear decommissioning investments is deferred as a regulatory asset or liability.

The total obligation for decommissioning currently is expected to be funded 100 percent by the external decommissioning trust fund, as approved by the MPUC, when decommissioning commences. The external funds are held in trust and in escrow. The portion in escrow is subject to refund if approved by the various commissions. In November 2012, the MPUC approved NSP-Minnesota's most recent nuclear decommissioning study which used 2011 cost data. The MPUC approved the use of a 60-year decommissioning scenario. This resulted in an approved annual accrual of $14.2 million for Minnesota retail customers, to be held in our external escrow fund.

Table of Contents

As of Dec. 31, 2013, NSP-Minnesota has accumulated $1.6 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters from the most recently approved decommissioning study. Xcel Energy believes future decommissioning cost expense, if necessary, will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO.

	Regulatory Basis	
(Thousands of Dollars)	2013	2012
Estimated decommissioning cost obligation from most recently approved study (2011 dollars)	$2,694,079	$2,694,079
Effect of escalating costs (to 2013 and 2012 dollars, respectively, at 3.63/2.63 percent)	189,924	93,327
Estimated decommissioning cost obligation (in current dollars)	2,884,003	2,787,406
Effect of escalating costs to payment date (3.63/2.63 percent)	5,697,285	5,793,882
Estimated future decommissioning costs (undiscounted)	8,581,288	8,581,288
Effect of discounting obligation (using risk-free interest rate)	(6,215,050)	(6,243,332)
Discounted decommissioning cost obligation	$2,366,238	$2,337,956
Assets held in external decommissioning trust	$1,627,026	$1,489,542
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	739,212	848,414

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

(Thousands of Dollars)	2013	2012	2011
Annual decommissioning recorded as depreciation expense: [a]			
Externally funded	$6,402	$—	$—
Internally funded (including interest costs)	—	(1,251)	(456)
Net decommissioning expense recorded	$6,402	$(1,251)	$(456)

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

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

15. Regulatory Assets and Liabilities

Xcel Energy Inc. and subsidiaries prepare their consolidated financial statements in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

Table of Contents

The components of regulatory assets shown on the consolidated balance sheets at Dec. 31, 2013 and 2012 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2013		Dec. 31, 2012	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations [(a)]	9	Various	$118,179	$1,192,808	$100,713	$1,552,375
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	359,215	—	321,680
Contract valuation adjustments [(b)]	1, 11	Term of related contract	3,620	153,393	3,775	147,755
Net AROs [(c)]	1, 13, 14	Plant lives	—	160,544	—	178,146
Conservation programs [(d)]	1	One to six years	55,088	63,275	60,956	84,146
Environmental remediation costs	1, 13	Various	4,735	119,175	3,986	109,377
Renewable resources and environmental initiatives	13	One to four years	46,076	37,858	59,518	38,138
Depreciation differences	1	One to seventeen years	10,918	95,844	5,274	50,057
Purchased power contract costs	13	Term of related contract	—	68,182	—	63,134
Losses on reacquired debt	4	Term of related debt	5,525	36,534	5,917	42,060
Nuclear refueling outage costs	1	One to two years	86,333	36,477	56,035	22,647
Gas pipeline inspection and remediation costs	12	Various	5,416	33,884	5,416	27,560
Recoverable purchased natural gas and electric energy costs	1	One to two years	42,288	15,495	32,098	8,340
Sherco Unit 3 deferral		Twenty-one years	503	10,063	—	—
State commission adjustments	1	Plant lives	444	14,204	374	12,181
Prairie Island EPU [(e)]	12	Pending rate cases	—	69,668	—	67,590
Property tax		Three years	18,427	30,626	6,005	12,010
Other		Various	20,249	11,973	12,910	24,833
Total regulatory assets			$417,801	$2,509,218	$352,977	$2,762,029

(a) Includes $303.3 million and $330.3 million for the regulatory recognition of the NSP-Minnesota pension expense of which $23.2 million and $24.3 million is included in the current asset at Dec. 31, 2013 and 2012, respectively. Also included are $17.7 million and $21.5 million of regulatory assets related to the nonqualified pension plan of which $2.2 million is included in the current asset at Dec. 31, 2013 and 2012, respectively.

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

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

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

(e) For the canceled Prairie Island EPU project, NSP-Minnesota plans to address recovery of incurred costs in the pending multi-year rate case.

The components of regulatory liabilities shown on the consolidated balance sheets at Dec. 31, 2013 and 2012 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2013		Dec. 31, 2012	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Plant removal costs	1, 13	Plant lives	$—	$906,403	$—	$922,963
Deferred electric and steam production and natural gas costs	1	Less than one year	96,574	—	90,454	—
DOE settlement	12	One to two years	44,208	1,131	22,700	1,131
Investment tax credit deferrals	1, 6	Various	—	56,535	—	59,052
Deferred income tax adjustment	1, 6	Various	—	43,581	—	44,667
Conservation programs [(b)]	1, 12	Less than one year	19,531	—	6,292	—
Contract valuation adjustments [(a)]	1, 11	Term of related contract	54,455	6,849	29,431	11,159
Gain from asset sales	12	One to three years	12,859	4,568	7,318	10,311
Renewable resources and environmental initiatives	12, 13	Various	2,499	1,412	256	1,412
Low income discount program		Less than one year	6,229	—	6,164	—
PSCo earnings test	12	One to two years	22,891	19,203	1,732	1,732
Other		Various	15,523	19,713	4,511	7,512
Total regulatory liabilities			$274,769	$1,059,395	$168,858	$1,059,939

(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.

Table of Contents

At Dec. 31, 2013 and 2012, approximately $306 million and $275 million of Xcel Energy's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes Prairie Island EPU costs, recoverable purchased natural gas and electric energy costs and certain expenditures associated with renewable resources and environmental initiatives.

16. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the year ended Dec. 31, 2013 were as follows:

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

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

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$4,107	(a)
Vehicle fuel derivatives	(90)	(b)
Total, pre-tax	4,017	
Tax benefit	(2,541)	
Total, net of tax	1,476	
Defined benefit pension and postretirement losses:		
Amortization of net loss	7,077	(c)
Prior service cost	372	(c)
Transition obligation	8	(c)
Total, pre-tax	7,457	
Tax benefit	(4,151)	
Total, net of tax	3,306	
Total amounts reclassified, net of tax	$4,782	

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and post retirement benefit costs. See Note 9 for details regarding these benefit plans.

17. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Table of Contents

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $87.1 million and $91.2 million as of Dec. 31, 2013 and 2012, respectively, included in the regulated natural gas utility segment.

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

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

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

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2013					
Operating revenues from external customers	$9,034,045	$1,804,679	$76,198	$—	$10,914,922
Intersegment revenues	1,332	2,717	—	(4,049)	—
Total revenues	$9,035,377	$1,807,396	$76,198	$(4,049)	$10,914,922
Depreciation and amortization	$840,833	$128,186	$8,844	$—	$977,863
Interest charges and financing costs	386,198	44,927	104,895	—	536,020
Income tax expense (benefit)	495,044	25,543	(36,611)	—	483,976
Net income (loss)	850,572	123,702	(26,040)	—	948,234

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2012					
Operating revenues from external customers	$8,517,296	$1,537,374	$73,553	$—	$10,128,223
Intersegment revenues	1,169	1,425	—	(2,594)	—
Total revenues	$8,518,465	$1,538,799	$73,553	$(2,594)	$10,128,223
Depreciation and amortization	$801,649	$115,038	$9,366	$—	$926,053
Interest charges and financing costs	397,457	49,456	119,324	—	566,237

Income tax expense (benefit)	465,626	50,322	(65,745)	—	450,203
Net income (loss)	851,929	98,061	(44,761)	—	905,229

Table of Contents

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2011					
Operating revenues from external customers	$8,766,593	$1,811,926	$76,251	$—	$10,654,770
Intersegment revenues	1,269	2,358	—	(3,627)	—
Total revenues	$8,767,862	$1,814,284	$76,251	$(3,627)	$10,654,770
Depreciation and amortization	$773,392	$106,870	$10,357	$—	$890,619
Interest charges and financing costs	402,668	52,115	108,336	—	563,119
Income tax expense (benefit)	473,848	57,408	(62,940)	—	468,316
Net income (loss)	788,967	101,842	(49,637)	—	841,172

18. Summarized Quarterly Financial Data (Unaudited)

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

(Amounts in thousands, except per share data)	Quarter Ended March 31, 2012	June 30, 2012	Sept. 30, 2012	Dec. 31, 2012
Operating revenues	$2,578,079	$2,274,668	$2,724,341	$2,551,135
Operating income	380,162	405,690	720,434	316,397
Net income	183,893	183,060	398,106	140,170
Earnings per share total — basic	$0.38	$0.38	$0.82	$0.29
Earnings per share total — diluted	0.38	0.38	0.81	0.29
Cash dividends declared per common share	0.26	0.27	0.27	0.27

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

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2013, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

163

Table of Contents

Internal Control Over Financial Reporting

No change in Xcel Energy’s internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy’s internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2013 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.’s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.’s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference.

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

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference.

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

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2014 Annual Meeting of Shareholders, which is incorporated by reference.

Table of Contents

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, 2013.
   Report of Independent Registered Public Accounting Firm — Financial Statements
   Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
   Consolidated Statements of Income — For the three years ended Dec. 31, 2013, 2012 and 2011.
   Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2013, 2012 and 2011.
   Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2013, 2012 and 2011.
   Consolidated Balance Sheets — As of Dec. 31, 2013 and 2012.
   Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2013, 2012 and 2011.
   Consolidated Statements of Capitalization — As of Dec. 31, 2013 and 2012.

2. Schedule I — Condensed Financial Information of Registrant.
   Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2013, 2012 and 2011.

3. Exhibits

*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
t	Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

Xcel Energy Inc.

1.01*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Barclays Capital Inc. (Exhibit 1.1 to Form 8-K dated March 5, 2013 (file no. 001-03034)).
1.02*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated (Exhibit 1.2 to Form 8-K dated March 5, 2013 (file no. 001-03034)).
1.03*	Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Morgan Stanley & Co. LLC (Exhibit 1.3 to Form 8-K dated March 5, 2013 (file no. 001-03034)).

PSCo

2.01* t	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers, and PSCo, as Purchaser, dated as of April 2, 2010 (excluding certain schedules and exhibits referred to in the agreement, as amended, which the Registrant agrees to furnish supplemental to the SEC upon request) (Exhibit 2.01 to Form 10-Q for the quarter ended June 30, 2010 (file no. 001-03034)).

Xcel Energy Inc.

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).

Xcel Energy Inc.

4.01*	Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, National Association (NA), as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.02*	

	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $300 million principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
4.03*	Supplemental Indenture No. 4 dated March 30, 2007 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $253.979 million aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).

165

Table of Contents

4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.05*	Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $400 million principal amount of 7.6 percent Junior Subordinated Notes, Series due 2068 (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.06*	Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.07*	Supplemental Indenture No. 5 dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $550 million principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 13, 2010).
4.08*	Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $250 million principal amount of 4.80 percent Senior Notes, Series due 2041 (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).
4.09*	Supplemental Indenture No. 7 dated as of May 1, 2013 between Xcel Energy and Wells Fargo Bank, NA, as Trustee, creating $450 million principal amount of 0.75 percent Senior Notes, Series due May 9, 2016 (Exhibit 4.01 to Form 8-K dated May 9, 2013 (file no. 001-03034)).

NSP-Minnesota

4.10*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year 1988, file no. 001-03034). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
	Supplemental 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, Rider A).
	Supplemental 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 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, Rider A).
4.11*	Supplemental Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.12*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.13*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture) (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.14*	Supplemental 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 Current Report on Form 10-Q, (file no. 001-31387) dated Sept. 30, 2002).
4.15*	Supplemental Trust Indenture dated Aug. 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $450 million principal amount of 8.0 percent First Mortgage Bonds, Series due Aug. 28, 2012 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 001-31387) dated Aug. 22, 2002).
4.16*	Supplemental Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25 percent First Mortgage Bonds, Series due

	July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 001-31387) dated July 14, 2005).
4.17*	Supplemental Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 001-31387) dated May 18, 2006).
4.18*	Supplemental Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
4.19*	Supplemental Indenture dated March 1, 2008 between NSP-Minnesota and The Bank of New York Trust Company, NA, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated March 11, 2008).
4.20*	Supplemental 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 Sept. 1, 2039 (Exhibit 4.01 of Form 8-K of NSP-Minnesota dated Nov. 16, 2009 (file no. 001-31387)).
4.21*	Supplemental 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 Form 8-K dated Aug. 11, 2010 (file no. 001-31387)).

Table of Contents

4.22*	Supplemental 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's Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
4.23*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60 percent First Mortgage Bonds, Series due May 15, 2023 (Exhibit 4.01 to NSP-Minnesota's Form 8-K dated May 20, 2013 (file no. 001-31387)).

NSP-Wisconsin

4.24*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust company, providing for the issuance of First Mortgage Bonds (Exhibit 4.01 to Registration Statement 33-39831).
4.25*	Supplemental Trust Indenture, dated April 1, 1991 (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).
4.26*	Supplemental Trust Indenture, dated Dec. 1, 1996 (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).
4.27*	Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firstar Bank, NA as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
4.28*	Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and US Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.29*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375 percent First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).
4.30*	Supplemental Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.700 percent First Mortgage Bonds, Series due Oct. 1, 2042 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Oct. 10, 2012 (file no. 001-03140)).

PSCo

4.31*	Indenture, dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).
4.32*	Indentures supplemental to Indenture dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee:

Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.	Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)	Sept. 1, 2002	8-K, Sept. 18, 2002 (001-03280)	4.01
Jan. 1, 1994	10-K, 1993	4(b)(3)	Sept. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.04
Sept. 2, 1994	8-K, September 1994	4(b)	March 1, 2003	S-3, April 14, 2003 (333-104504)	4(b)(3)
May 1, 1996	10-Q, June 30, 1996	4(b)	April 1, 2003	10-Q May 15, 2003 (001-03280)	4.02
Nov. 1, 1996	10-K, 1996 (001-03280)	4(b)(3)	May 1, 2003	S-4, June 11, 2003 (333-106011)	4.9
Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)	Sept. 1, 2003	8-K, Sept. 2, 2003 (001-03280)	4.02
April 1, 1998		4(b)	Sept. 15, 2003		4.100

	10-Q, March 31,1998 (001-03280)			Xcel 10-K, March 15, 2004 (001-03034)	
Aug. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.03	Aug. 1, 2005	PSCo 8-K, Aug. 18, 2005 (001-03280)	4.02

4.33*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).
4.34*	Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129.5 million Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file no. 001-03280).
4.35*	Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no. 001-03280) dated Aug. 14, 2007).
4.36*	Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80 percent First Mortgage Bonds, Series No. 18 due 2018 and $300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).

4.37*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).
4.38*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 16, 2010 (file no. 001-03280)).
4.39*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041 (Exhibit 4.01 to Form 8-K dated Aug. 9, 2011 (file no. 001-03280)).
4.40*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25 percent First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to PSCo's Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).
4.41*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50 percent First Mortgage Bonds, Series No. 25 due 2023 and $250 million principal amount of 3.95 percent First Mortgage Bonds, Series No. 26 due 2043 (Exhibit 4.01 to Form 8-K dated March 26, 2013 (file no. 001-03280)).

SPS

4.42*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.43*	First Supplemental Indenture dated March 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.3 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.44*	Second Supplemental Indenture dated Oct. 1, 2001 between SPS and The Chase Manhattan Bank (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 23, 2001).
4.45*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.46*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).
4.47*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).
4.48*	Supplemental Trust Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of Series G Senior Notes, 8.75 percent due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789)).
4.49*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
4.50*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50 percent First Mortgage Bonds, Series No. 1 due 2041 (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).

Xcel Energy Inc.

10.01*+	Xcel Energy Non-Qualified 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 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 Non-employee Directors' Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.04*	Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.05*+	Xcel Energy Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.06*+	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

Table of Contents

10.08*+	Xcel Energy Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.09*+	Xcel Energy 2010 Executive Annual Discretionary Award Plan (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2009).
10.10*+	Xcel Energy 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.11*+	Xcel Energy 2010 Executive Annual Discretionary Award Plan (as amended and restated effective Dec. 15, 2010) (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.12*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.13*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Performance Share Agreement (Exhibit 10.25 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14a*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.26 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14b*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Time-Based Restricted Stock Unit Agreement (Exhibit 10.14b to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2012).
10.15*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed April 5, 2011).
10.16*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (as amended and restated effective Nov. 29, 2011) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.17*+	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).
10.18*+	Amended and Restated Credit Agreement, dated as of July 27, 2012 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 (Incorporated by reference to Exhibit 99.01 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).
10.19*+	First Amendment dated Feb. 20, 2013 to the Xcel Energy Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.20*+	Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.21+	First Amendment dated May 21, 2013 to the Xcel Energy Inc. Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010).
10.22+	Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Non-Qualified Deferred Compensation Plan (2009 Restatement).
10.23+	Xcel Energy 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement.

NSP-Minnesota

10.24*	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).

10.25*	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).
10.26*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, NA, as Documentation Agent (Incorporated by reference to Exhibit 99.02 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).

Table of Contents

NSP-Wisconsin

10.27*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.28*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.05 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).

PSCo

10.29*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10I (1)).
10.30*	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10I (2)).
10.31*	Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.32*	Settlement Agreement among PSCo and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.33*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.03 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).

SPS

10.34*	Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).
10.35*	Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K, (file no. 001-03789) May 14, 1979 — Exhibit 5(A)).
10.36*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K, (file no. 3789) May 14, 1979 — Exhibit 5(B)).
10.37*	Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(b)).
10.38*	Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(c)).
10.39*	Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and SPS.
10.40*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.04 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).

Xcel Energy Inc.

12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm.
24.01	Powers of Attorney.

31.01	Principal Executive Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.

Table of Contents

101	The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, (ix) Schedule I, and (x) Schedule II.

171

Table of Contents

SCHEDULE I

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

	Year Ended Dec. 31		
	2013	2012	2011
Income			
Equity earnings of subsidiaries	$1,018,783	$976,395	$904,315
Total income	1,018,783	976,395	904,315
Expenses and other deductions			
Operating expenses	18,513	15,948	14,513
Other income	(206)	(652)	(760)
Interest charges and financing costs	102,914	116,731	104,499
Total expenses and other deductions	121,221	132,027	118,252
Income before income taxes	897,562	844,368	786,063
Income tax benefit	(50,672)	(60,861)	(55,109)
Net income	948,234	905,229	841,172
Dividend requirements on preferred stock	—	—	3,534
Premium on redemption of preferred stock	—	—	3,260
Earnings available to common shareholders	$948,234	$905,229	$834,378
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $5,897, $(2,331) and $(2,247), respectively	4,714	(3,311)	(3,205)
Derivative instruments, net of tax of $2,558, $(9,906) and $(24,488), respectively	1,488	(15,503)	(37,644)
Other, net of tax of $117, $135 and $(63), respectively	176	196	(93)
Other comprehensive income (loss)	6,378	(18,618)	(40,942)
Comprehensive income	$954,612	$886,611	$793,436
Weighted average common shares outstanding:			
Basic	496,073	487,899	485,039
Diluted	496,532	488,434	485,615
Earnings per average common share:			
Basic	$1.91	$1.86	$1.72
Diluted	1.91	1.85	1.72
Cash dividends declared per common share	1.11	1.07	1.03

See Notes to Condensed Financial Statements

Table of Contents

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

	Year Ended Dec. 31		
	2013	2012	2011
Operating activities			
Net cash provided by operating activities	$545,177	$815,209	$595,732
Investing activities			
Capital contributions to subsidiaries	(535,653)	(366,783)	(287,495)
Investments in the utility money pool	(1,778,000)	(640,000)	—
Return of investments in the utility money pool	1,706,000	658,000	—
Net cash used in investing activities	(607,653)	(348,783)	(287,495)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	297,000	52,000	(21,000)
Proceeds from issuance of long-term debt	447,595	—	246,877
Repayment of long-term debt	(400,000)	—	—
Proceeds from issuance of common stock	231,767	8,050	38,691
Repurchase of common stock	—	(18,529)	—
Purchase of common stock for settlement of equity awards	—	(23,307)	—
Redemption of preferred stock	—	—	(104,980)
Dividends paid	(514,042)	(486,757)	(474,760)
Net cash provided by (used in) financing activities	62,320	(468,543)	(315,172)
Net change in cash and cash equivalents	(156)	(2,117)	(6,935)
Cash and cash equivalents at beginning of period	602	2,719	9,654
Cash and cash equivalents at end of period	$446	$602	$2,719

See Notes to Condensed Financial Statements

Table of Contents

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

	Dec. 31	
	2013	2012
Assets		
Cash and cash equivalents	$446	$602
Accounts receivable from subsidiaries	240,450	195,438
Other current assets	51,086	11,497
Total current assets	291,982	207,537
Investment in subsidiaries	11,613,032	10,643,694
Other assets	105,073	143,760
Total other assets	11,718,105	10,787,454
Total assets	$12,010,087	$10,994,991
Liabilities and Equity		
Dividends payable	$139,432	$131,748
Short-term debt	476,000	179,000
Other current liabilities	6,954	31,032
Total current liabilities	622,386	341,780
Other liabilities	25,475	34,360
Total other liabilities	25,475	34,360
Commitments and contingencies		
Capitalization		
Long-term debt	1,796,276	1,744,774
Common stockholders' equity	9,565,950	8,874,077
Total capitalization	11,362,226	10,618,851
Total liabilities and equity	$12,010,087	$10,994,991

See Notes to Condensed Financial Statements

Table of Contents

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and OCI in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Related Party Transactions — Xcel Energy Inc. presents its related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31 were:

(Thousands of Dollars)	2013 Accounts Receivable	2013 Accounts Payable	2012 Accounts Receivable	2012 Accounts Payable
NSP-Minnesota	$57,596	$—	$63,682	$—
NSP-Wisconsin	6,933	—	7,631	—
PSCo	74,739	—	—	(3,362)
SPS	5,705	—	15,806	—
Xcel Energy Services Inc.	60,138	—	61,217	—
Xcel Energy Ventures Inc.	20,194	—	20,427	—
Other subsidiaries of Xcel Energy Inc.	15,145	—	30,037	—
	$240,450	$—	$198,800	$(3,362)

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $606 million, $757 million and $626 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively.

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2013
Lending limit	$250
Loan outstanding at period end	72

Average loan outstanding	109.8	
Maximum loan outstanding	182	
Weighted average interest rate, computed on a daily basis	0.31	%
Weighted average interest rate at end of period	0.25	
Money pool interest income	$0.1	

175

Table of Contents

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2013	Twelve Months Ended Dec. 31, 2012	Twelve Months Ended Dec. 31, 2011
Lending limit	$250	$250	$250
Loan outstanding at period end	72	—	18
Average loan outstanding	88.2	26.1	0.4
Maximum loan outstanding	243	226	43
Weighted average interest rate, computed on a daily basis	0.30 %	0.33 %	0.35 %
Weighted average interest rate at end of period	0.25	N/A	0.35
Money pool interest income	$0.3	$0.1	$—

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

Table of Contents

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2013, 2012 AND 2011
(amounts in thousands)

	Balance at Jan. 1	Additions Charged to Costs and Expenses	Charged to Other Accounts[a]	Deductions from Reserves[b][c]	Balance at Dec. 31
Allowance for bad debts:					
2013	$51,394	$37,627	$14,469	$50,383	$53,107
2012	58,565	33,808	16,033	57,012	51,394
2011	54,563	44,521	15,636	56,155	58,565
NOL and tax credit valuation allowances:					
2013	$3,314	$—	$—	$51	$3,263
2012	5,683	32	—	2,401	3,314
2011	1,927	4,379	—	623	5,683

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

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

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

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 21, 2014	By: /s/ TERESA S. MADDEN Teresa S. Madden Senior Vice President and Chief Financial Officer (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ BENJAMIN G.S. FOWKE III Benjamin G.S. Fowke III	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERESA S. MADDEN Teresa S. Madden	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Vice President and Controller (Principal Accounting Officer)
* Gail Koziara Boudreaux	Director
* Fredric W. Corrigan	Director
* Richard K. Davis	Director
* Albert F. Moreno	Director
* Richard T. O'Brien	Director
* Christopher J. Policinski	Director
* A. Patricia Sampson	Director
* James J. Sheppard	Director
*	Director

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

178