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.

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

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

Federal and State Regulatory Agencies

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

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Electric, Purchased Gas and Resource Adjustment Clauses

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

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
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

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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

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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

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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Energy Source Statistics

NSP System	Year Ended Dec. 31 2013 Millions of KWh	Percent of Generation	2012 Millions of KWh	Percent of Generation	2011 Millions of KWh	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	Percent	Nuclear Cost	Percent	Natural Gas Cost	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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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	

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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.

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NSP-Minnesota
Public Utility Regulation

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

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

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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.

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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.

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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.

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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