XCEL ENERGY INC
Form 10-K
February 24, 2012

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, 2011

or

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

Commission File Number: 1-3034
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
$7.60 Junior Subordinated Notes, Series due 2068	New York

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. x 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 x 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. x 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). xYes 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.
x 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 x No

As of June 30, 2011, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $11,774,380,709 and there were 484,542,416 shares of common stock outstanding.

As of Feb. 21, 2012, there were 486,828,501 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2012 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 integrated electric production and transmission system of NSP-Minnesota and NSP-Wisconsin 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.
Seren	Seren Innovations, Inc., a wholly owned subsidiary formerly a broadband communications network
SPS	Southwestern Public Service Co.
UE	Utility Engineering Corporation, an engineering, construction and design company
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
CPUC	Colorado Public Utilities Commission
DOE	United States Department of Energy
DOER	Division of Energy Resources (formerly the Office of Energy Security)
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EIB	New Mexico Environmental Improvement Board
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
NMED	New Mexico Environment Department
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OCC	Colorado Office of Consumer Counsel
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
Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EECRF	Energy efficiency cost recovery factor

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EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GAP	Gas affordability program
GCA	Gas cost adjustment
MCR	Mercury cost recovery rider
OATT	Open access transmission tariff
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
QSP	Quality of service plan
RDF	Renewable development fund
RES	Renewable energy standard
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

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARC	Aggregator of retail customers
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
CATR	Clean Air Transport Rule
CCN	Certificate of convenience and necessity
CIPS	Critical Infrastructure Protection Standards
CO2	Carbon dioxide
Codification	FASB Accounting Standards Codification
COLI	Corporate owned life insurance
CON	Certificate of need
CPCN	Certificate of public convenience and necessity
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
DSPP	Direct stock purchase plan
EEI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share

ERRP	Early retiree reimbursement program
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IFRS	International Financial Reporting Standards
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
MERP	Metropolitan Emissions Reduction Project

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MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator, Inc.
MRO	Midwest Reliability Organization
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
NTC	Notifications to construct
O&M	Operating and maintenance
OCI	Other comprehensive income
PBRP	Performance-based regulatory plan
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PJM	PJM Interconnection, LLC
PPA	Purchased power agreement
Provident	Provident Life & Accident Insurance Company
PRP	Potentially responsible party
PSP	Performance share plan
PV	Photovoltaic
REC	Renewable energy credit
RECB	Regional expansion criteria benefits
ROE	Return on equity
ROFR	Right of first refusal
RPS	Renewable portfolio standards
RSG	Revenue sufficiency guarantee
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
SIP	State implementation plan
SO2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
TSR	Total shareholder return
WECC	Western Electricity Coordinating Council
WTMPA	West Texas Municipal Power Agency

Measurements

Bcf	Billion cubic feet
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 2011, 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 Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipelines, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing 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 three core objectives: obtain stakeholder alignment; invest in our regulated utility businesses; and earn a fair return on our utility investments. 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 priority for Xcel Energy and is designed to meet customer and policy maker expectations while creating shareholder value.

NSP-Minnesota

NSP-Minnesota is an operating 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 5 percent of its total KWh sold in 2011. 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 89 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2011. 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 customers in the following industries: petroleum and coal, as well as food products. For small commercial and industrial customers, significant electric retail sales include customers in 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. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

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

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NSP-Wisconsin

NSP-Wisconsin is an operating 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. The wholesale customers served by NSP-Wisconsin comprised approximately 8 percent of its total KWh sold in 2011. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in the same service territory. NSP-Wisconsin provides electric utility service to approximately 251,000 customers and natural gas utility service to approximately 107,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2011. 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 customers in the following industries: food products, paper and allied products, electric and gas, as well as electronics. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: educational services and grocery and dining establishments. Generally, NSP-Wisconsin's earnings contribute approximately 5 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 an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 19 percent of its total KWh sold in 2011. 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 2011. 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 customers in the following industries: fabricated metal products, as well as electric and gas services. For small commercial and industrial customers, significant electric retail sales include customers in 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. Following settlement with the IRS during 2007, such policies were terminated. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

SPS

SPS is an operating 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 38 percent of its total KWh sold in 2011. SPS provides electric utility service to approximately 376,000 retail customers in Texas and New Mexico. Approximately 74 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2011. 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 customers in the oil and gas extraction industry. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: oil and gas extraction and crop related agricultural industries. Generally, SPS' earnings contribute approximately 5 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.

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.

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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 16 to the consolidated financial statements for further discussion relating to comparative segment revenues, income from continuing operations and related financial information.

Seasonality

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

Competition

Xcel Energy's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means, such as municipalization. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, their rates are competitive with currently available alternatives.

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 electric resource plans 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 requested continued authorization from the FERC to make wholesale electric sales at market-based prices. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion. NSP-Minnesota is a transmission owning member of the MISO RTO.

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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. 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 improvements to the A.S. King, High Bridge and Riverside plants, which were renovated under the MERP program.
- GAP — The GAP is a surcharge billed to all non-interruptible customers to recover the costs of offering a low-income customer co-pay program designed to reduce natural gas service disconnections.
- 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 is a rider that recovers the costs 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.

NSP-Minnesota has requested that the recovery of the costs associated with the EIR and RES be included in base rates, which is included in the Minnesota electric rate case currently pending approval with the MPUC.

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 cost 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. The FCA allows NSP-Minnesota to bill customers for the cost of fuel and related costs used to generate electricity at its plants and energy purchased from other suppliers. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or through rate cases.

Minnesota state law requires electric utilities to invest 1.5 percent of their state revenues in CIP, except NSP-Minnesota, which is required by law to invest 2 percent. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

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 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
NSP System	8,615	9,131	9,792	9,213

The peak demand for the NSP System typically occurs in the summer. The 2011 uninterrupted system peak demand for the NSP System occurred on July 18, 2011. 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.

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.

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NSP System Resource Plans — In December 2011, NSP-Minnesota filed an update to the 2011 through 2025 resource plan with the MPUC. To account for slower economic growth and the loss of NSP-Wisconsin's wholesale customers, NSP-Minnesota modified the five-year plan to include a recommendation to withdraw the Black Dog repowering project CON and to reassess the wind procurement plan and resource contingency plan in detail. The resource plan update also notified the MPUC that there have been changes in the size, timing, and cost estimates for the extended power uprate projects at the Prairie Island nuclear plant. As a result of these changes, NSP-Minnesota has notified the MPUC that it is completing a new economic and project design analysis and will submit a Change in Circumstances filing seeking reaffirmation of the CON approval before proceeding with the project. Some elements of the resource plan remain unchanged such as the extension of certain contracts, the Monticello nuclear generating plant extended power uprate project and the commitment to specific CIP program annual achievements.

NSP-Minnesota CapX2020 CON — 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 cost. The remainder of the costs will be born by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

NSP-Minnesota and Great River Energy filed four route permit applications with the MPUC in addition to a facility permit application with the SDPUC, a certificate of corridor compatibility application with the NDPSC and a CPCN application with the PSCW. The MPUC has issued route permits for the Minnesota portion of the Fargo, N.D. to St. Cloud, Minn. project and the Bemidji, Minn. to Grand Rapids, Minn. project. The remaining required permit activities are on-going in North Dakota, Wisconsin and Minnesota.

In December 2011, the Monticello, Minn. to St. Cloud, Minn. project was placed in service and MISO granted the final approval of the Brookings, S.D. project as an MVP.

Black Dog Repowering CON — In March 2011, NSP-Minnesota filed a request with Minnesota regulators to approve a CON for the project to retire its last two coal-burning units (Units 3 and 4) at the Black Dog plant in Burnsville, Minn. and replace them with combined-cycle natural gas burning units. Units 1 and 2 were converted to natural gas combined-cycle operation in 2002.

In December 2011, NSP-Minnesota requested to withdraw the CON and close the docket. The request to withdraw is pending an ALJ decision. NSP-Minnesota will reevaluate the Black Dog repowering project as part of the next resource plan expected in 2013.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of 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 the plant.

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 to approve the withdrawal of the application. A number of parties have challenged the DOE's authority to stop the project and withdraw the application. The utility industry, including Xcel Energy, is represented in the challenges by the NEI. In light of the DOE's plan to stop the project and withdraw its application, Xcel Energy in a separate action has requested the Secretary of Energy to set the fee collection rate for the Nuclear Waste Fund to zero until a definitive program is in place. In April 2010, the NEI, on behalf of its members, including Xcel Energy, filed a lawsuit against the DOE in federal court, requesting that the fee be suspended. The Secretary of Energy has convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. On Jan. 26, 2012, the Blue Ribbon Commission report was issued. The report provides numerous policy recommendations that will be considered by the Secretary of Energy.

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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.

Nuclear Spent Fuel Storage
In July 2011, a settlement agreement resolving the method by which NSP-Minnesota can recover certain incremental spent fuel storage costs through 2013 was approved with the DOE. The settlement does not address costs for used fuel storage after 2013; such costs could be the subject of future litigation. NSP-Minnesota received a $100 million payment in August 2011, of which $14.5 million was allocated to NSP-Wisconsin. As of Dec. 31, 2011, NSP-Minnesota has recorded the payment as restricted cash and a regulatory liability. Additionally, a claim for incremental spent fuel storage costs from 2009-2010 was submitted to the DOE in September 2011 and a claim for 2011 will be submitted to the DOE in May 2012.

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. As of Dec. 31, 2011, there were 29 casks loaded and stored at the Prairie Island plant and 10 canisters loaded and stored at the Monticello plant.

PFS — NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 2006, the U.S. Department of the Interior issued two findings: (1) that it would not grant the leases for rail or intermodal sites and (2) that it was revoking its previous conditional approval of the site lease between PFS and the Skull Valley Indian tribe. In 2007, PFS and the Skull Valley Band filed a lawsuit challenging these actions. The lawsuit remains pending. A judicial appeal of the NRC licensing decision has been held in abeyance pending the outcome of the lawsuit challenging the DOI decisions. The existence of PFS as a licensed out-of-state storage option remains a credible alternative if PFS and the Skull Valley Band can prevail in the pending litigation and if the federal government fails to make progress with their obligation to take title and remove spent nuclear fuel from all domestic reactor sites.

See Note 14 to the consolidated financial statements for further discussion regarding the nuclear generating plants.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear plants. The event at the nuclear plant in Fukushima, Japan could impact the NRC's deliberations on NSP-Minnesota's power uprates discussed below. This event could also result in additional regulation by the NRC, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force to develop recommendations for NRC consideration on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures and licensing processes.

In July 2011, the task force released its recommendations. The report confirmed the safety of U.S. nuclear energy facilities and recommends actions to enhance U.S. nuclear plant readiness to safely manage severe events. In October 2011, the NRC Staff identified the near-term regulatory actions to be taken and prioritized these recommendations into a three-tiered approach. In December 2011, the NRC Commissioners approved the prioritization of the first tier and second tier recommendations. The NRC Staff and the industry are working to establish guidance to implement the NRC's direction regarding resolution of the Tier 1 recommendations and final action by the NRC on these recommendations is expected in the first half of 2012.

The industry is considering a wide range of strategies to address anticipated NRC regulation. Depending on the approach selected, preliminary estimates range from $20 million to $250 million dollars of capital investment approximately over the next five to eight years to address postulated safety upgrades to the Xcel Energy nuclear facilities. The low end of this range would apply if the NRC accepts the industry's 'flex' approach which provides diverse and portable sources of providing emergency power and water. The high end estimate considers added cost of requiring permanently installed modifications with a higher degree of engineering analysis to meet nuclear standards for flooding, seismic and other local environmental considerations. Xcel Energy believes the costs of implementing these requirements would be recoverable through regulatory mechanisms, and it does not expect a material impact on its results of operations.

To better coordinate response activities, the U.S. nuclear energy industry has created a steering committee made up of representatives from major electric sector organizations, including Xcel Energy, to integrate and coordinate the industry's ongoing responses. In addition, the NRC has conducted technical inspections at Xcel Energy's nuclear facilities to assess the capability to respond to extraordinary consequences similar to those that occurred at Fukushima, Japan. These inspections identified no significant findings or issues.

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Nuclear Plant Power Uprates and Life Extension

Life Extensions — In 2006, the NRC renewed the Monticello operating license allowing the plant to operate until 2030. In June 2011, the NRC issued renewed operating licenses for Prairie Island Units 1 and 2, allowing Unit 1 to operate until 2033 and Unit 2 until 2034.

Monticello Nuclear Plant Extended Power Uprate — In 2008, NSP-Minnesota filed for both state and federal approvals of an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello nuclear plant. The MPUC approved the CON for the extended power uprate in 2008. The filing was placed on hold by the NRC Staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. NSP-Minnesota has been working with the industry and regulatory agencies to address this issue and had expected to receive a regulatory decision on the license application in 2012. In October 2011, the Advisory Committee recommended that all licensing actions that credit the use of containment accident pressure be suspended until the causes and risks of Japan's Fukushima incident are better understood. NSP-Minnesota is evaluating the impact of this recommendation on the timing of the license decision which will likely result in a delay of the approval. NSP-Minnesota has rescheduled the remaining equipment changes needed to complete the Monticello power uprate project during the planned spring 2013 refueling outage.

Prairie Island Nuclear Extended Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2, which the MPUC approved in 2009. Analysis of recent extended power uprate submittals to the NRC concluded that significant additional design work beyond current schedule and cost plan estimates are now being required to submit a successful application. As a result, NSP-Minnesota is completing an economic and new project design analysis to determine project impacts and anticipates submitting a Change in Circumstances filing with the MPUC in the first quarter of 2012.

Total capital investment between 2012 and 2015 for the Monticello and Prairie Island power uprate and life cycle management activities is estimated to be approximately $640 million.

Fuel Supply and Costs

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

	Coal*		Nuclear		Natural Gas		Weighted Average
NSP System Generating Plants	Cost	Percent	Cost	Percent	Cost	Percent	Fuel Cost
2011	$2.06	55 %	$0.89	40 %	$6.56	5 %	$ 1.82
2010	1.89	51	0.83	42	6.29	7	1.73
2009	1.78	57	0.70	39	7.36	4	1.61

* 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 40 days of coal inventory. Coal supply inventories at Dec. 31, 2011 and 2010 were approximately 48 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 2011 and 2010, coal requirements for the NSP System's major coal-fired generating plants were approximately 9.5 million tons. The estimated coal requirements for 2012 are approximately 8 million tons, including adjustments to account for Sherco Unit 3, which was shut down in November 2011 after experiencing a significant failure of its turbine, generator, and exciter systems. It is uncertain when Sherco Unit 3 will recommence operations.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 99 percent of their coal requirements in 2012, 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 2012 and 2013. 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 2017 and approximately 66 percent of the requirements for 2018 through 2025.
- Current contracts for conversion services cover 100 percent of the requirements through 2017 and approximately 78 percent of the requirements for 2018 through 2025.
- Current enrichment service contracts cover 100 percent of the requirements through 2016 and approximately 95 percent of the requirements for 2017 through 2025.

Fabrication services for Monticello and Prairie Island are 100 percent committed through 2025 and 2014, respectively. A contract for fuel fabrication services for Prairie Island is currently being negotiated for 2015 and beyond.

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 some of the 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, 2010, the NSP System's commitments related to gas supply contracts were $14 million and commitments related to gas transportation and storage contracts were approximately $499 million. At Dec. 31, 2011, the NSP System did not have any commitments related to gas supply contracts; however, commitments related to gas transportation and storage contracts, which expire in various years from 2012 to 2028, were approximately $462 million. The NSP System has limited on-site fuel oil storage facilities and relies on the spot market for incremental supplies, if needed.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, biomass, solar and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 19.7 percent and 18.3 percent of the NSP System's total owned and purchased energy for 2011 and 2010, respectively. Biomass and solar power comprised approximately 2.8 percent and 2.9 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind and hydroelectric sources. As of Dec. 31, 2011, the NSP System is in compliance with its renewable portfolio standards, which require generation from renewable resources of 15 percent and 8.89 percent of Minnesota and Wisconsin electric retail sales, respectively.

The NSP System also offers customer-focused renewable energy initiatives. The Windsource® program allows customers in Minnesota and Wisconsin to purchase a portion or all of their electricity from renewable sources. Approximately 22,715 and 22,676 customers purchased 176,522 MWh and 166,979 MWh of electricity under the Windsource program in 2011 and 2010, respectively. 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 300 PV systems with approximately 3 MW of aggregate capacity and 166 PV systems with approximately 1 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

Wind — The NSP System acquires the majority of its wind energy from purchased power agreements with wind farm owners, primarily in Southwestern Minnesota. The NSP System currently has more than 100 of these agreements in place, with facilities ranging in size from under 1 MW to more than 200 MW. 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 $39 and $37 for 2011 and 2010, 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.

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Generally, contracts executed in 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012.

The NSP System also fully owns and operates two wind farms. The 101 MW Grand Meadow Wind Farm began generating electricity in 2008 and the 201 MW Nobles Wind Farm began generating electricity in 2010. Collectively, the NSP System had over 1,600 MW and nearly 1,500 MW of wind energy on its system at the end of 2011 and 2010, respectively. Wind energy comprised 9.4 percent and 8.0 percent of the total owned and purchased energy on the NSP System for 2011 and 2010, respectively.

In 2011, NSP-Minnesota agreed to purchase 200 MW of wind power from Geronimo Wind Energy's Prairie Rose Wind Farm, which is expected to be completed in 2012. By the end of 2012, the NSP System plans to have over 1,900 MW of wind energy on its system.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and purchased power agreements. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 253 MW of capacity. For most of 2011, there were eight purchased power agreements in place which provided approximately 24 MW of hydroelectric capacity. In December 2011, an additional nine MW of purchased hydroelectric capacity was brought onto the system. Additionally, the NSP System purchases significant generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities. Hydroelectric energy comprised 7.5 percent and 7.4 percent of the total owned and purchased energy on the NSP System for 2011 and 2010, respectively.

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 NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. NSP-Wisconsin has requested continued authorization from the FERC to make wholesale electric sales at market-based prices. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion. 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.

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 must submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities must defer the amount of any fuel cost over-collection or under-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. These rules went into effect in January 2011.

NSP-Wisconsin's wholesale electric rate schedules include a fuel clause adjustment to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

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, reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

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Wisconsin Energy Efficiency and Conservation Goals — In June 2011, the Wisconsin biennial budget bill was signed into law, which rolled back the projected increases for state energy efficiency and conservation funding effective in 2012. Based on this action, NSP-Wisconsin expects to be allocated approximately $8.2 million of the statewide program costs in 2012, increasing to approximately $9.1 million by 2014. Historically, NSP-Wisconsin has recovered these costs in rate charges to Wisconsin retail customers and expects to recover the program costs in rates going forward.

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 — An application for a CPCN for the Wisconsin portion of the 345 KV CapX2020 project was filed with the PSCW in January 2011. This line is expected to entail construction of approximately 150 miles of new transmission lines between Hampton, Minn. and La Crosse, Wis. with approximately 50 miles located in Wisconsin at an estimated cost of $200 million to NSP-Wisconsin.

In June 2011, the PSCW determined the application was complete, which triggers the 360-day deadline for the PSCW to grant a CPCN for the project. In January 2012, the PSCW Staff issued a final Environmental Impact Statement that raises questions about the need for the project and the applicants preferred routes. There have also been issues raised by the Wisconsin Department of Transportation and the WDNR regarding portions of the proposed route and there are route location alternatives if the PSCW determines these issues warrant such a decision. Testimony was filed in January and February 2012 and public hearings are expected to be held in March 2012. The PSCW is expected to issue a final decision in mid-2012 regarding the transmission line.

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 NERC electric reliability standards and natural gas transactions in interstate commerce. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion.

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. Effective January 2011, the PCCA began to recover the revenue requirement associated with the purchase of the Blue Spruce Energy Center and Rocky Mountain Energy Center. Recovery of the revenue requirement for these facilities will be removed from the PCCA to base rates in mid 2012, as part of the PSCo electric rate case.

- 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. Beginning 2010, the CPUC approved recovery of the full amount of DSM-related costs through the combination of base rates and a DSMCA tracker mechanism.
- RESA — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of 2 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.

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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 renewable energy purchase and generation costs through a fuel clause and in exchange receive renewable energy credits associated with those resources.

PBRP and QSP Requirements — PSCo currently operates under an electric PBRP. This regulatory plan includes 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 through 2012. PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
PSCo	6,311	6,436	6,896	6,313

The peak demand for PSCo's system typically occurs in the summer. The 2011 uninterrupted system peak demand for PSCo occurred on July 18, 2011 and was higher than 2010 and the 2012 forecasted peak demand primarily due to backup load to serve the non-PSCo joint owners of Comanche Unit 3, which was offline when the peak demand occurred.

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.

PSCo Resource Plan — In October 2011, PSCo filed the 2011 electric resource plan. Beginning in 2017, PSCo is projected to have relatively low resource needs and has proposed to fill these needs with a competitive resource acquisition process. The CPUC will consider the resource plan in two phases. In the first phase, the CPUC will review planning assumptions, competitive bidding structure, and determine if PSCo should acquire generation technology. The first phase is expected to be completed by the end of 2012. In the second phase, PSCo will conduct the competitive acquisition process, which is expected to be submitted to the CPUC for approval in 2013.

RES Compliance Plan — Colorado has a law that mandates that at least 30 percent of PSCo's energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. PSCo has filed the 2012 and 2013 RES compliance plan. PSCo proposed to acquire up to 30 MW of customer-sited solar projects each year and up to 6 MW of community scale solar projects. A decision on the 2012 and 2013 plan is expected in the first quarter of 2012. PSCo currently recovers any incentives paid through a combination of the ECA and RESA cost-recovery mechanisms.

Solar*Rewards Program — In March 2011, the CPUC approved a settlement that limits the amount of customer sited solar generation that PSCo will purchase, caps the amount PSCo will spend on customer sited solar generation and shifts from up-front payments to pay-for-performance. The settlement gives PSCo a presumption of prudence, for both the existing RESA balance, and the future RESA balance if PSCo performs consistent with the acquisition terms of the settlement.

Separately, the CPUC approved a change to the treatment of REC trading margins that allows the customers' share of the margins through the end of the pilot period, approximately $54 million, to be netted against the RESA regulatory asset balance. During the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

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CACJA — The CACJA required PSCo to file a comprehensive plan to reduce annual emissions of NOx by at least 70 to 80 percent or greater from 2008 levels by 2017 from the coal-fired generation identified in the plan. The plan allows PSCo to propose emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by 2017. The total investment associated with the adopted plan is approximately $1.0 billion through 2017 and the rate impact is expected to increase future bills on average by 2 percent annually.

In December 2010, the CPUC approved the following:

- Shutdown Cherokee Units 2 and 1 in 2011 and 2012, respectively, and Cherokee Unit 3 (365 MW in total) by the end of 2015, after a new natural gas combined-cycle unit is built at Cherokee Station (569 MW);
- Fuel-switch Cherokee Unit 4 (352 MW) to natural gas by 2017;
- Shutdown Arapahoe Unit 3 (45 MW) and fuel-switch Unit 4 (111 MW) in 2014 to natural gas;
- Shutdown Valmont Unit 5 (186 MW) in 2017;
- Install SCR for controlling NOx and a scrubber for controlling SO2 on Pawnee Generating Station in 2014;
- Install SCRs on Hayden Unit 1 in 2015 and Hayden Unit 2 in 2016; and
- Convert Cherokee Unit 2 and Arapahoe Unit 3 to synchronous condensers to support the transmission system.

PSCo has received CPCNs for the conversion of Cherokee Unit 2 to a synchronous condenser, for the decommissioning of Cherokee Unit 1 and Unit 2, and for the Pawnee emissions controls. In addition, PSCo has filed for CPCNs for the new natural gas combined-cycle at Cherokee station and the Hayden emissions controls.

San Luis Valley-Calumet-Comanche Transmission Project — In May 2009, PSCo and Tri-State Generation and Transmission Association filed a joint application with the CPUC for a 230 KV and 345 KV line and substation construction project. The line was intended to assist in bringing solar power in the San Luis Valley to customers. The line was originally expected to be placed in-service in 2013; however, due to delays in the siting and permitting of the line, the in-service date was delayed.

In October 2011, in conjunction with the filing of the electric resource plan, PSCo determined that due to lower projected load growth, lower gas prices and the higher cost of solar thermal generation, it was unlikely to need the transmission line in the foreseeable future. A CPUC decision on the resource plan is expected in late 2012.

SmartGridCity™ CPCN — As part of the PSCo 2010 electric rate case, the CPUC included recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred by PSCo to develop and operate SmartGridCity™, subject to refund, and ordered PSCo to file for a CPCN for that project.

In February 2011, the CPUC approved the CPCN and allowed recovery of approximately $28 million of the capital cost and 100 percent of the O&M costs and ordered PSCo to file for a rate reduction in April 2011 to reflect the lower level of capital in rate base. On July 1, 2011, PSCo implemented an annual rate reduction of $2.8 million. In December 2011, PSCo filed an application addressing the additional information requested. A decision is expected in the third quarter of 2012.

Boulder, Colo. Franchise Agreement — 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 (and extended the tax until the earlier to occur of (1) Dec. 31, 2017, (2) when Boulder decides not to create a municipal utility, or (3) when Boulder commences delivery of municipal electric utility services) for the purpose of 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, but not limited to, the level of initial rates and debt service coverage. Boulder has retained legal counsel specializing in condemnation and plans to retain legal counsel specializing in FERC matters. The City Council has not yet decided whether it will proceed with the formation of a municipal electric utility or with commencing a condemnation proceeding. Should Boulder proceed with these actions and be successful, PSCo would seek to obtain full compensation for the property and business taken by Boulder and for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

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Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for 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
PSCo Generating Plants	Cost	Percent	Cost	Percent	Fuel Cost
2011	$ 1.77	76 %	$ 4.98	24 %	$ 2.54
2010	1.58	85	5.05	15	2.11
2009	1.52	82	3.99	18	1.97

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, 2011 and 2010 were approximately 48 and 34 days usage, respectively. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2011 and 2010, PSCo's coal requirements for existing plants were approximately 10.5 and 10.7 million tons, respectively. The estimated coal requirements for 2012 are approximately 11.6 million tons.

PSCo has contracted for coal supply to provide 100 percent of its coal requirements in 2012, 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 2012 and 2013. 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, 2010, PSCo's commitments related to gas supply contracts were approximately $817 million and commitments related to gas transportation and storage contracts were approximately $838 million. At Dec. 31, 2011, PSCo's commitments related to gas supply contracts, which expire in various years from 2012 through 2021, were approximately $730 million and commitments related to gas transportation and storage contracts, which expire in various years from 2012 through 2060, were approximately $819 million.

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, biomass, solar, and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 14.6 percent and 11.7 percent of PSCo's total owned and purchased energy for 2011 and 2010, respectively. Biomass, solar and hydroelectric power comprised approximately 2.2 percent and 1.4 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind. As of Dec. 31, 2011, PSCo is in compliance with its renewable portfolio standards which require generation from renewable resources of 12 percent of electric retail sales.

PSCo acquires the majority of its wind energy from purchased power agreements with wind farm owners, primarily in Colorado and Wyoming. PSCo currently has 18 of these agreements in place, with facilities ranging in size from under 3 MW to 300 MW. 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 for each of 2011 and 2010.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.

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Generally, contracts executed in 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012.

In 2011, the new 252 MW Cedar Point Wind Project and the 251 MW Cedar Creek II Wind Farm began commercial operations. PSCo has long-term purchased power agreements to acquire the output of both facilities. PSCo has agreed to purchase 200 MW of wind power from NextEra Energy Resources' Limon Wind Energy Center and an additional 200 MW from NextEra Energy Resources' Limon Wind Energy Center II, which are both expected to be completed in 2012. The average cost over the 25 year term of these contracts is approximately $35 per MWh, which is lower than the average cost per MWh of purchased wind energy on the PSCo system. By the end of 2012, PSCo plans to have approximately 2,200 MW of wind on its system.

Additionally, PSCo owns and operates the 26.4 MW Ponnequin Wind Farm in northern Colorado, which has been in service since 1999. PSCo collectively had nearly 1,800 MW and 1,300 MW of wind energy on its system at the end of 2011 and 2010, respectively. Wind energy comprised 12.4 percent and 10.3 percent of PSCo's total owned and purchased energy for 2011 and 2010, respectively.

PSCo also offers customer-focused renewable energy initiatives. The Windsource program allows customers to purchase a portion or all of their electricity from renewable sources. Approximately 35,843 and 38,762 customers in Colorado purchased 211,511 MWh and 212,900 MWh of electricity under the Windsource program in 2011 and 2010, respectively. 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 9,600 PV systems with approximately 110 MW of aggregate capacity and over 7,100 PV systems with approximately 76 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

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 increase. 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. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion.

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

- 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.

- EECRF — The EECRF rider recovers costs associated with providing energy efficiency programs in Texas.
- TCRF — The TCRF rider recovers transmission infrastructure improvement costs and changes in wholesale transmission charges. Effective February 2011, the recovery of the costs associated with the TCRF rider were included in base rates and the TCRF rider was set to zero dollars.
- PCRF — The PCRF rider allows recovery of certain purchased power costs. Effective February 2011, the recovery of the costs associated with the PCRF rider are included in base rates, and the PCRF rider was eliminated.

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. Based on regulatory approval in 2011, SO2 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.

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The fixed fuel and purchased energy recovery factor provides for accounting of 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. In the fourth quarter of 2011, a fuel surcharge was implemented in Texas for recovery of the under-recovered fuel and purchased energy costs and interest. The surcharge will remain in place until October 2012.

PUCT regulations require periodic examination of SPS' fuel and purchased energy costs, the efficient use of fuel and purchased energy, the fuel acquisition and management policies and the 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 periodically request authority to continue using its FPPCAC. The NMPRC reviews SPS' use of its FPPCAC since the filing of its previous fuel clause continuation filing. As a follow-up to an SPS rate case, the NMPRC conducted an audit of SPS' fuel and purchased power costs for a 12-month period from July 2009 through July 2010 and the tracking mechanism to capture costs and revenues associated with SPS' RECs from assorted wind projects for that period. In December 2011, the NMPRC authorized SPS to continue its use of its FPPCAC and approved the prudency of the use of the FPPCAC for the period through Dec. 31, 2010.

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

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
SPS	5,038	4,985	5,210	5,155

The peak demand for the SPS system typically occurs in the summer. The 2011 uninterrupted system peak demand for SPS occurred on Aug. 2, 2011.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases and DSM 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.

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.

SPS Transmission NTC — In 2010, SPP approved the first of a series of new transmission lines in several states, including Texas, New Mexico and Oklahoma, to help improve electric reliability, strengthen the existing transmission grid and provide outlets for additional renewable wind generation. As a member of SPP, SPS accepts NTCs for SPP identified lines. SPS has accepted NTCs for approximately 119 miles of transmission lines at an estimated cost of $126 million. Under its jurisdiction, the PUCT has thus far approved the construction of two 115 KV and one 230 KV electric transmission line as part of the project at an estimated cost of $29.1 million. These approved transmission lines are expected to be completed in the first half of 2013.

TUCO to Woodward District Extra High Voltage Interchange — In June 2009, SPP directed SPS to construct a 178 mile 345 KV transmission line between Lubbock, Texas and Woodward, Okla. The estimated investment in the new line is $184 million and will be recovered from SPP members, including SPS, in accordance with the SPP OATT and the retail ratemaking process. In March 2011, SPS filed a CCN to build the line with the PUCT. A decision is expected in the first quarter of 2012.

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). This generating unit will add 168 MW of capacity to the SPS service territory. In February 2012, the NMPRC approved the CCN.

SPS Resource Plans — SPS is required to develop and implement a renewable portfolio plan in which ten 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. In 2009, the NMPRC granted SPS a variance to allow SPS to delay meeting its solar energy requirement until 2012 provided that SPS compensates for any shortfall of the 2011 solar energy requirement during 2012 through 2014. SPS executed and received NMPRC approval for a total of 50 MW of PV solar energy PPAs. SPS requested and was granted a variance from the NMPRC to extend the time to implement a portion of the diversity requirements to January 2014. SPS is continuing its efforts to acquire viable biomass generation or make a biogas purchase to meet the diversity portion of its renewable energy portfolio plan in New Mexico.

SPS solicited public participation throughout 2011 in its New Mexico 2012 Integrated Resource Planning (IRP) and anticipates filing the IRP with the NMPRC in July 2012.

CSAPR — CSAPR addresses long range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. CSAPR is discussed further at Note 13 to the consolidated financial statements — Environmental Contingencies. Xcel Energy is in the process of determining various scenarios to respond to the CSAPR depending on whether the CSAPR is upheld, reversed, or modified.

If the CSAPR is upheld and unmodified, Xcel Energy believes that the CSAPR could ultimately require the installation of additional emission controls on some of SPS' coal-fired electric generating units. If compliance is required in a short time frame, SPS may be required to redispatch its system to reduce coal plant operating hours, in order to decrease emissions from its facilities prior to the installation of emission controls. The expected cost for these scenarios vary significantly and SPS has estimated capital expenditures of approximately $470 million over the next four years for the CSAPR.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for 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	Fuel Cost
2011	$ 1.89	67 %	$ 4.37	33 %	$ 2.71
2010	1.84	71	4.59	29	2.64
2009	1.74	73	3.80	27	2.3

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

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO Inc. (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, 2011 and 2010, coal inventories at SPS were approximately 43 and 41 days supply, respectively. TUCO has coal agreements to supply 96 percent of SPS' coal requirements in 2012, 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.

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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 2012 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. These transportation rates are subject to revision based upon FERC or Railroad Commission of Texas 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. SPS' commitments related to gas supply contracts were approximately $24 million and $28 million and commitments related to gas transportation and storage contracts were approximately $242 million and $233 million at Dec. 31, 2011 and Dec. 31, 2010, respectively.

Renewable Energy Sources

SPS' renewable energy portfolio includes wind, solar and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 8.2 percent and 7.9 percent of SPS' total owned and purchased energy for 2011 and 2010, respectively. Solar and hydroelectric power comprised approximately 0.4 percent and 0.3 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind. As of Dec. 31, 2011, SPS is in compliance with its renewable portfolio standards, which require generation from renewable resources of approximately 3 percent and 10 percent of Texas and New Mexico electric retail sales, respectively.

SPS acquires its wind energy from long-term purchased power agreements with wind farm owners, primarily 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 2 MW to 161 MW. 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. Additionally, SPS is required to purchase another 240 MW of wind energy from qualified generating facilities as defined in the Public Utilities Regulatory Policy Act of 1978. These purchases are made at the SPP Locational Imbalance Price rather than through long term purchased power agreements. The average cost per MWh of wind energy under these contracts was approximately $26 and $27 for 2011 and 2010, 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 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012. At the end of 2011 and 2010, SPS had nearly 700 MW of wind energy on its system.

Additionally, in late 2010, SPS signed an agreement to purchase the output of the 161 MW Spinning Spur Wind Ranch which is expected to be completed in 2012. Wind energy comprised 7.8 percent and 7.6 percent of SPS' total owned and purchased energy for 2011 and 2010, respectively.

SPS also offers customer-focused renewable energy initiatives. The Windsource program allows customers in New Mexico to purchase a portion or all of their electricity from renewable sources. Approximately 1,233 and 1,224 customers purchased 7,005 MWh and 7,162 MWh of electricity under the Windsource program in 2011 and 2010, respectively. 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 70 PV systems with approximately 5 MW of aggregate capacity and 16 PV systems with less than 1 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

Wholesale Commodity Marketing Operations

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

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, 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 discussion of other regulatory matters.

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FERC Transmission Planning and Cost Allocation — The FERC has approved the open access transmission planning processes for Xcel Energy and the RTOs serving the NSP System and SPS (MISO and SPP, respectively) set forth in tariffs filed in compliance with FERC Order 890. The FERC has also approved SPP tariffs providing for the partial regional allocation of the cost of new transmission facilities.

In July 2011, the FERC issued Order 1000 adopting modified rules for regional transmission planning, wholesale transmission cost allocation and transmission development. The new rules would eliminate any preferential right at the federal level for an incumbent transmission provider to construct transmission facilities subject to regional cost allocation, referred to as a ROFR. The transmission planning processes will be subject to additional tariff revisions subsequent to Order 1000 compliance filings due in October 2012.

Order 1000 will require significant changes in transmission planning and cost allocation mechanisms in the WestConnect where PSCo is located. The impacts of the provisions of Order 1000 regarding transmission planning and cost allocation on SPS and the NSP System are expected to be less significant as they already participate in regional planning and cost allocation processes. Xcel Energy is in the process of determining the impacts of the new Order 1000 requirements related to future transmission development and ownership. Irrespective of the new rules, the utility subsidiaries are pursuing several new transmission facility projects.

ARCs — In 2009, the FERC adopted rules requiring RTOs to allow ARCs to offer demand response aggregation services to end-use customers of large utilities unless the relevant state regulatory agency prohibited the operation of ARCs. Under MISO’s proposed tariff revisions, ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Minnesota. In 2010, MISO requested its compliance tariff revisions be effective in June 2010, and the MPUC, NDPSC, SDPUC, PSCW, and MPSC all issued orders prohibiting, or temporarily prohibiting, the operation of ARCs in their states.

In January 2011, the MPUC asked public utilities to explore the potential of programs with ARCs that compliment existing CIP initiatives. In September 2011, NSP-Minnesota agreed to propose a pilot program that would expand existing retail CIP services in a manner analogous to an ARC, but complementary with its existing CIP programs. NSP-Minnesota is waiting on the MPUC for further guidance prior to proceeding with the pilot program.

In December 2011, the FERC issued orders denying rehearing of the rules and approving most aspects of the MISO compliance filing. The FERC retained the rules allowing state regulatory authorities to prohibit ARCs within their state.

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

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

FERC has issued an order on establishing principles for the review proceeding and encouraging a settlement. The settlement process is in progress.

FERC Penalty Guidelines — The Energy Act required the FERC to adopt new regulations to implement various aspects of the Energy Act. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

In September 2010, the FERC issued a policy statement establishing guidelines to determine the financial penalties that would be applied for violations of FERC statutes, rules and orders, including violations of NERC mandatory reliability standard violations investigated by the FERC. The guidelines established a base violation level for various types of violations, plus mitigating or aggravating factor adders and multipliers, depending on the nature and severity of the violation. Under the guidelines, penalties can range between a minimal amount and $290 million. The guidelines indicate that the FERC can deviate from the guidelines in its discretion. The guidelines can apply to any investigation where the FERC Staff has not begun settlement negotiations regarding an alleged violation.

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While Xcel Energy cannot predict the ultimate impact new FERC regulations will have on its results of operations, cash flows or financial position, Xcel Energy continues to take action to comply with existing rules and to implement new FERC rules and regulations as they become effective.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement commenced a non-public investigation of the transmission service arrangements across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the FERC issued a preliminary report alleging Xcel Energy violated certain FERC policies, rules and approved tariffs that could result in material penalties under the FERC penalty guidelines. The report did not constitute a finding by the FERC. Xcel Energy disagreed with the preliminary report and demonstrated compliance with applicable standards. In November 2011, Xcel Energy and SPP filed proposed tariff revisions clarifying the transmission arrangements across the Lamar Tie Line prospectively.

In January 2012, the FERC approved a stipulation and consent agreement in which Xcel Energy did not admit any violations but agreed to pay a $2 million civil penalty. The FERC contemporaneously issued an order approving changes to the Xcel Energy OATT to allow continued network service arrangements under the tariff.

NERC Compliance Audits and Self-Reports — In 2010 and 2011, the NSP System, PSCo and SPS filed self-reports with the MRO, the WECC and the SPP, respectively, regarding potential violations of certain NERC CIPS. Based on the issues identified with CIPS compliance, the utility subsidiaries submitted a mitigation plan that provides for a comprehensive review of the utility subsidiaries' CIPS compliance programs. Following this comprehensive review, additional self-reports of potential violations were filed.

In 2011, the NSP System was subject to a comprehensive triennial audit by the MRO regarding compliance with various NERC mandatory reliability standards, including CIPS. The MRO found potential violations of seven standards; five are related to CIPS. The written MRO audit reports have been issued and referred to MRO's enforcement function for further action. None of the potential violations are expected to result in a material penalty.

In May 2011, PSCo was subject to a comprehensive triennial audit by the WECC regarding compliance with various NERC mandatory reliability standards. In December 2011, PSCo and WECC agreed to a settlement in principle of five violations of four NERC reliability standards, including the two violations self-reported prior to the May 2011 audit. The violations were all self-identified and self-reported to WECC. PSCo agreed to pay an immaterial penalty to resolve all five reliability standard violations. Following execution of the settlement agreement, the agreement must be approved by NERC's Board of Trustees and filed with FERC for further approval.

In July 2011, SPS filed a self-report with the SPP regarding a potential violation of a NERC reliability standard. Mitigation actions associated with this self-report are complete, and the violation is not expected to result in a material penalty.

NERC Compliance Investigations — In September 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection as a result of a series of transmission line outages. In addition, service to approximately 790 MW of load was temporarily interrupted, primarily in Saskatchewan, Canada. In late 2010, NERC transferred responsibility for completing the compliance investigation to the MRO. The final outcome of the compliance investigation, and whether and to what extent penalties for alleged violations may be assessed, is unknown at this time.

In February 2010, the NERC notified NSP-Minnesota that it was commencing a non-public investigation of NSP-Minnesota maintenance practices associated with insulating oil levels in bulk electric system substations, as the result of an anonymous complaint received by the NERC. In February 2011, NERC transferred responsibility for completing the compliance investigation to the MRO. The MRO reviewed the status of insulating oil levels during the triennial compliance audit in the first quarter 2011. In July 2011, the NERC issued a preliminary findings report with three potential violations of NERC reliability standards, which NSP-Minnesota responded to in September 2011. The final outcome of the compliance investigation and whether and to what extent penalties for alleged violations may be assessed is unknown at this time.

NERC Advisory Regarding Impact of Transmission Field Conditions on Facility Ratings — In 2010, the NERC issued an advisory requiring utilities to perform an assessment of field versus assumed "as built" transmission infrastructure conditions and allowed for affected entities to complete their initial assessment and corrective actions by 2013 and 2014, respectively. The advisory compliance cost for the utility subsidiaries is estimated at $25 million to $30 million. Xcel Energy will seek recovery through applicable rate-making mechanisms.

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Electric Transmission Rate Regulation — The FERC regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control of their electric transmission assets for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO RTO. SPS is a member of the SPP RTO. Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates. In 2009, PSCo filed a tariff to participate with other utilities in WestConnect, a consortium of utilities offering regionalized non-firm transmission services. The WestConnect tariff was effective in the first quarter of 2009 and the FERC approved a two year extension in the second quarter of 2011. The WestConnect tariff has not had a material impact on PSCo transmission usage or revenues. WestConnect may provide wholesale energy market functions in the future, but would not be an RTO.

MISO Transmission Pricing — Certain new higher voltage transmission facilities determined by MISO to meet RECB eligibility criteria in the MISO tariff are subject to an allocation of 20 percent of the facility costs to all loads in the 15 state MISO region. Under specific FERC orders, certain new high voltage transmission facilities determined by MISO to meet MVP eligibility criteria are subject to an allocation of 100 percent of the facility costs to all loads on the MISO region. The MISO independent board of directors must approve MVP eligibility before the costs of a specific project are eligible for regional rate recovery under the MISO tariff. Certain parties have appealed the FERC MVP tariff orders to the Seventh Circuit Court of Appeals.

The MISO regional cost allocation methods require other customers in MISO to contribute to cost recovery for certain new transmission facilities constructed by the NSP System. MISO approved the eligibility of the CapX2020 Fargo, N.D. and La Crosse, Wis. transmission expansion projects for 20 percent regional allocation. In addition, in December 2011, the Brookings, S.D. CapX2020 transmission line was approved by MISO as an MVP, and thus eligible for 100 percent regional cost allocation. The CapX2020 Bemidji, Minn. transmission expansion project is not eligible for regional cost allocation. However, the NSP System also pays a share of the costs of projects constructed by other transmission-owning entities in the MISO region found to be eligible for regional cost allocation. 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 are expected to be material in future periods. The RECB and MVP cost allocation processes may be subject to future change to comply with FERC Order 1000.

MISO Wholesale Capacity Markets — In July 2011, MISO filed to implement a resource adequacy tariff to be effective Oct. 1, 2012. The tariff would establish a MISO capacity market, which would allow the NSP System to purchase or sell short-term capacity in order to comply with regional reliability planning reserve requirements. The MISO tariff proposal would allow utility capacity arrangements determined through state resource planning processes to be deemed compliant with the tariff. The tariff proposal is pending FERC action.

Market-Based Rate Rules — Each of the Xcel Energy Inc. utility subsidiaries was granted market-based rate authority. Under market-based rates, the NSP System was reauthorized to sell wholesale power at market-based rates in June 2009. In December 2011, the NSP System filed for continued market-based rate authority, as required by FERC's triennial market power review rules effective Jan. 1, 2012. The request is pending FERC action. SPS was reauthorized to sell at market-based rate rules outside its service territory by the FERC in 2010. PSCo was reauthorized to sell at market-based rates outside its service territory in 2011. Presently, Xcel Energy Inc.'s utility subsidiaries may not sell power at market-based rates within the PSCo and SPS balancing authorities, where they have been found to have market power under the FERC's applicable analysis. Both PSCo and SPS have cost-based coordination tariffs that they may use to make sales in their balancing authorities.

RSG Charges — The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive 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. MISO has since issued multiple related compliance filings with the FERC. In recent RSG filings, MISO has proposed to allocate a greater portion of the RSG costs related to resources committed for voltage and local reliability requirements to the market participants with the loads that benefit from such commitments. MISO has also proposed to mitigate the offers of resources committed for voltage regulation and local reliability requirements, which is expected to reduce RSG charges to other market participants under the current tariff. NSP-Minnesota is permitted to recover the RSG costs through FCA mechanisms approved by the regulators in each jurisdiction.

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Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31					
	2011		2010		2009	
Electric sales (Millions of KWh)						
Residential	25,278		25,143		24,039	
Large commercial and industrial	27,419		27,167		26,647	
Small commercial and industrial	35,597		35,650		34,608	
Public authorities and other	1,135		1,100		1,079	
Total retail	89,429		89,060		86,373	
Sales for resale	20,177		20,532		21,588	
Total energy sold	109,606		109,592		107,961	
Number of customers at end of period						
Residential	2,919,660		2,906,248		2,905,105	
Large commercial and industrial	1,129		1,112		1,100	
Small commercial and industrial	415,755		413,750		414,603	
Public authorities and other	69,350		70,413		71,677	
Total retail	3,405,894		3,391,523		3,392,485	
Wholesale	78		88		101	
Total customers	3,405,972		3,391,611		3,392,586	
Electric revenues (Thousands of Dollars)						
Residential	$2,712,340		$2,622,284		$2,355,138	
Large commercial and industrial	1,616,596		1,533,993		1,422,353	
Small commercial and industrial	3,025,416		2,956,077		2,649,354	
Public authorities and other	129,826		126,345		116,933	
Total retail	7,484,178		7,238,699		6,543,778	
Wholesale	936,875		960,505		886,417	
Other electric revenues	345,540		252,641		274,528	
Total electric revenues	$8,766,593		$8,451,845		$7,704,723	
KWh sales per retail customer	26,257		26,260		25,460	
Revenue per retail customer	$2,197		$2,134		$1,929	
Residential revenue per KWh	10.73	¢	10.43	¢	9.80	¢
Large commercial and industrial revenue per KWh	5.90		5.65		5.34	
Small commercial and industrial revenue per KWh	8.50		8.29		7.66	
Wholesale revenue per KWh	4.64		4.68		4.11	

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Energy Source Statistics

	Year Ended Dec. 31					
	2011		2010		2009	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	57,014	50 %	57,832	51 %	56,282	50 %
Natural Gas	25,080	22	25,947	23	27,175	24
Nuclear	13,781	12	15,012	13	13,670	12
Wind (a)	11,216	10	9,885	9	9,114	8
Hydroelectric	4,203	4				