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PROJECT 18688

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

or

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

Commission file number: 001-03789

SOUTHWESTERN PUBLIC SERVICE COMPANY
(Exact name of registrant as specified in its charter)

New Mexico	**75-0575400**
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)

Tyler at Sixth, Amarillo, Texas 79101
(Address of principal executive offices)

Registrant's telephone number, including area code: **303-571-7511**

Securities registered pursuant to Section 12(b) of the Act: **None**

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

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

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

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

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

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

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

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

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

As of Feb. 28, 2011, 100 shares of common stock, par value $1 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

Xcel Energy Inc.'s Definitive Proxy Statement for its 2011 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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

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

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Subsidiaries and Affiliates	
NCE	New Century Energies, Inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado, a Colorado corporation
SPS	Southwestern Public Service Company, a New Mexico corporation
utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo, SPS
Xcel Energy	Xcel Energy Inc., a Minnesota corporation
Federal and State Regulatory Agencies	
EIB	New Mexico Environmental Improvement Board
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission. The U.S. agency that regulates the rates and services for transportation of electricity and natural gas; the sale wholesale electricity, in interstate commerce, including the sale of electricity at market-based rates; hydroelectric generation licensing; and accounting requirements for utility holding companies, service companies and public utilities.
IRS	Internal Revenue Service
NERC	North American Electric Reliability Council. A self-regulatory organization, subject to oversight by the FERC and government authorities in Canada, to develop and enforce reliability standards.
NMED	New Mexico Environment Department
NMPRC	New Mexico Public Regulatory Commission. The state agency that regulates the retail rates and services and other aspects of SPS' operations in New Mexico. The NMPRC also has jurisdiction over the issuance of securities by SPS.
PUCT	Public Utility Commission of Texas. The state agency that regulates the retail rates, services and other aspects of SPS' operations in Texas.
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality
Electric and Resource Adjustment Clauses	
EECRF	Energy efficiency cost recovery factor
FPPCAC	Fuel and purchased power cost adjustment clause. Allows SPS to use a monthly adjustment factor for fuel and purchased power.
OATT	Open Access Transmission Tariff
TCR	Transmission cost recovery
TCRF	Transmission cost recovery factor
Other Terms and Abbreviations	
AFUDC	Allowance for funds used during construction. Defined in regulatory accounts as non-cash accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in property accounts and included in income.
ALJ	Administrative law judge. A judge presiding over regulatory proceedings.
APBO	Accumulated Postretirement Benefit Obligation
ARO	Asset Retirement Obligation. Obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.
ASC	FASB Accounting Standards Codification
BAL	Balancing authority
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Convenience and Necessity
CIPS	Critical Infrastructure Protection Standards

CO_2	Carbon dioxide
Codification	FASB Accounting Standards Codification
CWIP	Construction work in progress
derivative instrument	A financial instrument or other contract with all three of the following characteristics: • An underlying and a notional amount or payment provision or both; • Requires no initial investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors; and • Terms require or permit a net settlement, can be readily settled net by means outside the contract or provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.
distribution	The system of lines, transformers, switches, and mains that connect electric transmission systems to customers.
DOI	Department of Investigation
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
GAAP	Generally accepted accounting principles
generation	The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in MW (capacity) or MW hours (energy).
GHG	Greenhouse gas
JOA	Joint operating agreement among Xcel Energy's utility subsidiaries
LIBOR	London Interbank Offered Rate
mark-to-market	The process whereby an asset or liability is recognized at fair value.
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investor Services
native load	The customer demand of retail and wholesale customers whereby a utility has an obligation to serve: e.g., an obligation to provide electric service created by statute or long-term contract.
NOPR	Notice of proposed rulemaking
NOx	Nitrogen oxide
O&M	Operating and maintenance
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PJM	PJM Interconnection, L.L.C.
PPA	Purchased power agreement
PRP	Potentially responsible party
rate base	The investor-owned plant facilities for generation, transmission, and distribution and other assets used in supplying utility service to the consumer.
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right of first refusal
RPS	Renewable Portfolio Standard. A regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal.
RTO	Regional Transmission Organization. An independent entity, which is established to have "functional control" over a utility's electric transmission systems, in order to provide non-discriminatory access to transmission of electricity.
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
unbilled revenues	Amount of service rendered but not billed at the end of an accounting period. Cycle meter-reading practices result in unbilled consumption between the date of last meter reading and the end of the period.
underlying	A specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event such as a scheduled payment under a contract.
wheeling or transmission	An electric service wherein high voltage transmission facilities of one utility system are used to transmit power generated within or purchased from another system.
WTMPA	West Texas Municipal Power Agency

Measurements

Btu	British thermal unit. A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels.
KW	Kilowatts (one KW equals one thousand watts)
KWh	Kilowatt hours
MMBtu	One million Btus
MW	Megawatts (one MW equals one thousand KW)
Volt	The unit of measurement of electromotive force. Equivalent to the force required to produce a current of one ampere through a resistance of one ohm. The unit of measure for electrical potential. Generally measured in kilovolts.
Watt	A measure of power production or usage.

PROJECT 18688
COMPANY OVERVIEW

SPS was incorporated in 1921 under the laws of New Mexico. 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 36 percent of its total sales in 2010. SPS provides electric utility service to approximately 375,000 retail customers in Texas and New Mexico. Approximately 74 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2010. Generally, SPS' earnings contribute approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

In October 2010, SPS sold certain electric distribution assets in Lubbock, Texas to Lubbock Power and Light (LP&L) for $87 million. This sale resulted in a pre-tax gain of approximately $20 million which will be shared with retail customers in Texas, and has been deferred as a regulatory liability pending the determination of the sharing by the PUCT. SPS' retail sales in Lubbock were approximately 3 percent of SPS' total energy sales in both 2009 and 2010. SPS anticipates it will sell the same amount of power to the city under existing wholesale power arrangements with WTMPA.

SPS focuses on growing through investments in electric rate base to 1) meet growing customer demands, 2) comply with environmental and renewable energy initiatives and 3) maintain or increase reliability and quality of service to customers. SPS files periodic rate cases, establishes formula rate or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations. Our environmental initiatives are designed to meet customer and policy maker expectations while creating shareholder value.

ELECTRIC UTILITY OPERATIONS

Overview

Environmental Regulations, Climate Change and Clean Energy — Electric utilities are subject to a significant array of environmental regulations. Further, there are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change.

While the regulations, climate change and clean energy continue to evolve, SPS has undertaken a number of initiatives to meet current and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. These initiatives include emission reduction programs, energy efficiency and conservation programs, renewable energy development and technology exploration projects. Although the impact of climate change policy on SPS will depend on the specifics of state and federal policies, legislation and regulation, we believe that, based on prior state commission practice, SPS would be granted the authority to recover the cost of these initiatives through rates.

Utility Competition — The FERC has continued its efforts to promote more competitive wholesale markets through open-access transmission and other means. As a consequence, SPS and its wholesale customers can purchase generation resources from competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to the utility subsidiaries' to serve their native load.

Transmission — In June 2010, the FERC issued a NOPR that would eliminate any preferential right at the federal level for an incumbent transmission provider to construct new transmission facilities in its service territory (referred to as a ROFR). The NOPR is pending FERC action. Irrespective of the NOPR, the utility subsidiaries are pursuing several new transmission facility projects.

The FERC has approved the open access transmission planning processes for SPP, the RTO serving the SPS System.

In addition to utility-sponsored transmission expansion, several large "overlay" transmission projects have been proposed to construct 765 KV transmission facilities through the service areas of the utility subsidiaries. SPS is participating in certain overlay project evaluations to ensure that any projects proposed are the most cost effective options. It is not certain if or when specific overlay projects may be constructed and placed in service.

Alternative Energy Options — SPS' 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 or steam or chilled water for heating, cooling, and manufacturing purposes, or the option of relocating their facilities to a lower cost region. While SPS faces these challenges, it believes its rates are competitive with currently available alternatives.

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 and does 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 mandatory NERC electric reliability standards and certain 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 discussion).

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — 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. The regulations allow retail fuel factors to change up to three times per year.

There is an accounting of over- or under-recovery of fuel and purchased energy expenses under the fixed factor. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4 percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

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

The NMPRC has authorized SPS to use a monthly adjustment factor for a FPPCAC for SPS' New Mexico retail jurisdiction. 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 SPS' last 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 the 12-month period from July 2009 through July 2010. Audit results are expected in the first quarter of 2011.

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.

Texas EECRF Rider — PUCT regulations established an EECRF rider under which electric utilities may recover costs associated with providing energy efficiency programs. The EECRF rider must be included in a utility's tariff and may be established in a utility's base rate case or through a separate request seeking to establish an EECRF. Previously, the PUCT concluded that the rule did not apply to SPS and that energy efficiency costs should be recovered in base rates. As part of the settlement in SPS' last base rate case, SPS reached a negotiated settlement with the parties and included base rate recovery amounts explicitly designated for energy efficiency. In August 2010, the PUCT adopted a new rule that increases the energy efficiency goals and makes SPS subject to the same requirements with respect to the EECRF as other utilities in the state. Parties can appeal the application of the rule to SPS when SPS files for the rider in the spring of 2011.

Jones CCN — In August 2010, 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 with the PUCT. The NMPRC approved a similar CON in December 2010.

New Mexico Energy Efficiency Disincentive Rulemaking — During the 2008 New Mexico legislative session, increased energy efficiency goals and removal of disincentives were adopted. In 2010, the NMPRC adopted an amended rule incorporating the legislative changes. The rule had an interim mechanism that provides for recovery of disincentives and required utilities to file permanent rate design or other means of removing disincentives.

In July 2010, SPS filed its application to remove disincentives and requested direct lost margin recovery. A final order was received in December 2010 approving $3.3 million for 2010 and 2011. A hearing in this case that focuses on the appropriate long-term mechanism is scheduled for March 2011.

Solar Contract Approval — In December 2009, SPS entered into five solar energy PPAs with SunEdision, LLC (SunE), for the procurement of solar energy and associated RECs to meet its solar diversity requirements. The SunE PPAs involve five facilities, each consisting of 10 MW of capacity for a term of 20 years. In September 2010, the NMPRC approved the SunE PPAs and SPS' proposed cost recovery.

New Mexico GHG Regulations — In 2010, the New Mexico EIB adopted regulations to limit and reduce GHGs, including CO_2 emissions from power plants and other industrial sources. SPS and several other utilities and industry groups have filed separate appeals with the New Mexico Court of Appeals challenging the validity of these GHG regulations. Compliance costs for these reductions or offsets may increase electricity rates to New Mexico customers. While regulated utilities generally recover costs resulting from regulatory requirements, SPS may not recover all costs related to complying with the regulatory requirements imposed on SPS under the existing EIB regulations. The effect of these regulations on the financial condition of SPS is uncertain, due to the lack of certainty about the validity of these challenged regulations, and also due to the relatively small proportion of SPS total greenhouse gases that are emitted in New Mexico.

TUCO Inc. (TUCO) to Woodward District Extra High Voltage (EHV) 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 $149 million and will be recovered from SPP members, including SPS, in accordance with the SPP OATT and the retail ratemaking process. Preliminary work has begun for construction from the TUCO substation to the Oklahoma border. TRC was contracted to do the routing and environmental impact studies. SPS is expected to file an application requesting approval to build the line in March 2011.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2011, assuming normal weather, is listed below.

System Peak Demand (in MW)			
2008	2009	2010	2011 Forecast
4,996	5,038	4,985	5,142

The peak demand for the SPS system typically occurs in the summer. The 2010 uninterrupted system peak demand for SPS occurred on Aug. 4, 2010.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases and demand side management 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 purchase power contracts typically require a periodic payment to secure the capacity from and a charge for the associated energy actually purchased. SPS also makes short-term purchases to comply with minimum availability requirements, and to obtain energy at a lower cost.

SPS Resource Planning

Integrated Resource Planning (IRP) — SPS is soliciting public participation throughout 2011 in its New Mexico 2012 IRP filing through public and webcast meetings. SPS anticipates filing the IRP with the NMPRC in July 2012.

Renewable Energy Portfolio Plan — 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 solar energy requirement for 2011 during 2012 through 2014. SPS executed and received NMPRC approval for a total of 50 MW of photovoltaic solar energy PPAs. SPS requested a variance from the NMPRC to extend the time to implement its other resource diversity requirements to January 2012.

Approved Resource Additions — SPS plans to add a new third gas turbine to its Jones Plant site in Lubbock, Texas. SPS received CCN approvals from the PUCT and NMPRC for the turbine which will become operational in June 2011. This generating unit will add 168 MW of capacity to the SPS service territory. SPS also executed a purchase power agreement with Calpine Energy Services, LP for 200 MW from 2012 through 2018 that was approved by the NMPRC in December 2010.

Pending Resource Solicitations — SPS finalized a power purchase agreement for 161 MW of wind resources, and requested approval from the NMPRC in December 2010. SPS released a request for proposal in 2009 for approximately 43,000 MWh annually of biomass generation or an equivalent amount of biogas of approximately 326,000 MMBtu annually to meet its other resource diversity requirements in New Mexico. SPS is continuing its efforts to acquire viable biomass generation or a biogas purchase to meet its renewable energy portfolio plan in New Mexico.

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

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 Fuel
	Cost	Percent	Cost	Percent	Cost
2010	$ 1.84	71 %	$ 4.59	29 %	$ 2.64
2009	1.74	73	3.80	27	2.30
2008	1.86	71	8.41	29	3.78

See additional discussion of fuel supply and costs under Item 1A — Risk Factors.

Fuel Sources

Coal — SPS purchases all of its coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters, and handlers. For the Harrington station, the coal supply contract with TUCO expires in 2016. For the Tolk station, the coal supply contract with TUCO expires in 2017. As of Dec. 31, 2010 and 2009, coal inventories at the Harrington site were approximately 38 and 46 days supply, respectively. As of Dec. 31, 2010 and 2009, coal inventories at the Tolk site were approximately 45 and 54 days supply, respectively. TUCO has coal agreements to supply 90 percent of SPS' coal requirements in 2011, 57 percent of SPS' coal requirements in 2012, and 44 percent of SPS' coal requirements in 2013, which are sufficient quantities to meet the primary needs of the Harrington and Tolk stations.

Natural gas — SPS uses both firm and interruptible natural gas 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 2011 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. At Dec. 31, 2010, SPS' commitments related to supply contracts were approximately $28 million and transportation and storage contracts were approximately $233 million.

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 supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures About Market Risk.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, accounting practices and certain other activities of SPS, and enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 11 to the financial statements for a discussion of other regulatory matters.

FERC Penalty Guidelines Issued — 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 establish 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. Penalties range between a minimal amount and $72.5 million based on an application of a multiplier. 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.

While Xcel Energy cannot predict the ultimate impact new FERC regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement new FERC rules and regulations as they become effective.

NERC Electric Reliability Standards Compliance

Compliance Audits and Self Reports

In 2008, SPS filed self-reports with SPP, the NERC regional entity for the SPS system, relating to failure to complete certain generation station battery tests, relay maintenance intervals and record keeping associated with certain CIPS. In 2009, SPS reached agreement with SPP that would resolve all open audit findings and self reports by payment of a non-material penalty. SPS reached a settlement agreement with SPP. This settlement agreement has been approved by the NERC and was filed for FERC approval in December 2010. In January 2011, the FERC issued an order accepting the NERC approval with no further action.

In March 2010, SPP conducted a spot check to evaluate compliance with the NERC CIPS. The regional entity issued a non-public final report in August 2010 alleging violations of certain CIPS requirements, including certain violations common to all Xcel Energy utility subsidiaries. Xcel Energy disputes the alleged violations and is working to resolve the issues. To what extent the regional entities or NERC may seek to impose penalties for violations of CIPS is unknown at this time.

In 2010, SPP conducted its triennial audit of SPS compliance with certain NERC mandatory electric reliability standards. The audit did not include an evaluation of SPS compliance with NERC CIPS. The auditors found no standards violations. The written SPP audit report is now being completed.

In November 2010, SPS filed a self-report with SPP regarding potential violations of certain NERC CIPS. Additional self-reports of potential violations of CIPS were filed in January 2011. Based on the issues identified with CIPS compliance, SPS submitted a mitigation plan that provides for a comprehensive review of its CIPS compliance programs. Whether and to what extent penalties may be assessed against SPS for the issues identified and self-reported to date is unclear.

NERC Advisory Regarding Impact of Transmission Field Conditions on Facility Ratings — In October 2010, the NERC issued an advisory requiring utilities to perform an assessment of field versus assumed "as built" transmission infrastructure conditions. In December 2010, the NERC issued a revised advisory extending the period for affected entities to complete their initial assessment and corrective actions until 2013 and 2014, respectively. The advisory compliance cost for SPS is estimated at $11.4 million. SPS will seek recovery through applicable rate-making mechanisms.

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 and the sale of electric transmission services to an 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.

Proposed Rulemaking on Transmission Planning and Cost Allocation — In June 2010, the FERC issued a NOPR regarding transmission planning and cost allocation. The NOPR would (1) require that local and regional transmission planning processes address public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighboring transmission planning regions of interregional facilities; (3) eliminate any preferential right at the federal level for an incumbent transmission provider to construct new transmission facilities in its service territory, referred to as a ROFR; and (4) require cost allocation methods for transmission facilities to satisfy newly established cost allocation principles. The FERC will consider the written comments provided on the NOPR prior to adopting a final rule. The content of the final rule cannot be predicted at this time; however, limiting an incumbent utility's preferential ROFR to build transmission in its service territory states may have a negative impact on longer-term growth opportunities for the Xcel Energy utility subsidiaries.

Market-Based Rate Rules — Each of the Xcel Energy utility subsidiaries was granted market-based rate authority. SPS was reauthorized to sell at market-based rate rules outside its service territory by the FERC in July 2010. Presently, the Xcel Energy utility subsidiaries may not sell power at market-based rates within the SPS balancing authorities, where they have been found to have market power under the FERC's applicable analysis. SPS has cost-based coordination tariffs that it may use to make sales in its balancing authorities.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement, DOI, commenced a non-public investigation of use of network transmission service arrangements across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the DOI 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 does not constitute a finding by the FERC, which may accept, modify or reject any or all of the preliminary conclusions set forth in the report. Xcel Energy provided a response that disagreed with the preliminary report and demonstrated compliance with applicable standards. In December 2010, the DOI initiated settlement negotiations with Xcel Energy regarding possible resolution of the non-public investigation. The final outcome of the FERC DOI investigation and to what extent FERC may seek to impose penalties for violations is unknown at this time.

Electric Operating Statistics

	Year Ended Dec. 31,		
	2010	2009	2008
Electric sales (Millions of KWh)			
Residential	3,681	3,539	3,505
Commercial and industrial	14,323	13,981	14,134
Public authorities and other	571	552	555
Total retail	18,575	18,072	18,194
Sales for resale	10,674	10,209	11,453
Total energy sold	29,249	28,281	29,647
Number of customers at end of period			
Residential	295,671	313,063	311,345
Commercial and industrial	73,424	77,217	75,734
Public authorities and other	6,134	6,088	5,987
Total retail	375,229	396,368	393,066
Wholesale	39	45	38
Total customers	375,268	396,413	393,104
Electric revenues (Thousands of Dollars)			
Residential	$ 300,173	$ 284,760	$ 323,782
Commercial and industrial	733,476	703,300	936,674
Public authorities and other	38,929	34,933	46,434
Total retail	1,072,578	1,022,993	1,306,890
Wholesale	485,068	408,460	632,332
Other electric revenues	55,344	27,770	53,552
Total electric revenues	$ 1,612,990	$ 1,459,223	$ 1,992,774
KWh sales per retail customer	49,503	45,593	46,287
Revenue per retail customer	$ 2,858	$ 2,581	$ 3,325
Residential revenue per KWh	8.15 ¢	8.05 ¢	9.24 ¢
Commercial and industrial revenue per KWh	5.12	5.03	6.63
Wholesale revenue per KWh	4.54	4.00	5.52

Natural Gas Facilities Used for Electric Generation

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

ENVIRONMENTAL MATTERS

SPS' facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. SPS has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. SPS' facilities have been designed and constructed to operate in compliance with applicable environmental standards.

SPS strives to comply with all environmental regulations applicable to its operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have upon SPS' operations. For more information on environmental contingencies, see Note 12 to the financial statements.

EMPLOYEES

The number of full-time SPS employees at Dec. 31, 2010 and 2009 was 1,192 and 1,186, respectively. Of these full-time employees, 804, or 67 percent, and 795, or 67 percent, respectively, are covered under collective bargaining agreements which expire in October 2011. Employees of Xcel Energy Services Inc., a subsidiary of Xcel Energy, also provide services to SPS and are not considered in the above amounts.

Item 1A — Risk Factors

Oversight of Risk and Related Processes

The goal of Xcel Energy's risk management process, which includes SPS, is to understand, manage and, when possible, mitigate material risk; management is responsible for identifying and managing risks, while Xcel Energy's Board of Directors oversees and holds management accountable. As described more fully below, SPS is faced with a number of different types of risk. We confront legislative and regulatory policy and compliance risks, including risks related to climate change and emission of CO_2; risks for recovery of capital and operating costs; resource planning and other long-term planning risks, including resource acquisition risks; financial risks, including credit, interest rate and capital market risks; and macroeconomic risks, including risks related to economic conditions and changes in demand for our products and services. Cross-cutting risks such as these are discussed and managed across business areas and coordinated by Xcel Energy's and SPS' senior management. Our risk management process has three parts: identification and analysis, management and mitigation and communication and disclosure.

Our management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economy and the environment to identify risks. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the securities disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Management seeks to mitigate the risks inherent in the implementation of Xcel Energy's and SPS' strategy. The process for risk management and mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups, and overall business management. At a threshold level, we have developed a robust compliance program and promote a culture of compliance, which mitigates risk. Building on this culture of compliance, we manage and mitigate risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of corporate areas such as internal audit, the corporate controller and legal services. While we have developed a number of formal structures for risk management, many material risks affect the business as a whole and are managed across business areas.

Management also communicates with Xcel Energy's Board and key stakeholders regarding risk. Management provides information to Xcel Energy's Board in presentations and communications over the course of the year. Senior management presents an assessment of key risks to the Board annually. The presentation of the key risks and the discussion provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Based on this presentation, the Board reviews risks at an enterprise level and confirms risk management and mitigation are included in Xcel Energy's and SPS' strategy. The guidelines on corporate governance and committee charters define the scope of review and inquiry for the Board and committees. The standing committees also oversee risk management as part of their charters. Each committee has responsibility for overseeing aspects of risk and our management and mitigation of the risk. The Xcel Energy Board has overall responsibility for risk oversight. As described above, the Board reviews the key risk assessment process presented by senior management. This key risk assessment analyzes the most likely areas of future risk to Xcel Energy. The Xcel Energy Board also reviews the performance and annual goals of each business area. This review, when combined with the oversight of specific risks by the committees, allows the Board to confirm risk is considered in the development of goals and that risk has been adequately considered and mitigated in the execution of corporate strategy. The presentation of the assessment of key risks also provides the basis for the discussion of risk in our public filings and securities disclosures.

Risks Associated with Our Business

Environmental Risks

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

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, to install pollution control equipment at our facilities, clean up spills and correct environmental hazards and other contamination. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e. clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2010, these sites included third party sites, such as landfills, for which we are alleged to be a potentially responsible party that sent hazardous materials and wastes.

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

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

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

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

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

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

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

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

Financial Risks

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

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

Our profitability is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of our costs incurred in a test year. Thus, the rates we are allowed to charge may or may not match our costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs. Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers.

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

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

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

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment in property, plant and equipment; consequently, we are an active participant in debt and equity markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy, such as the recent concerns regarding European sovereign debt. Capital market disruption events, and resulting broad financial market distress, such as the events surrounding the collapse in the U.S. sub-prime mortgage market, could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

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

We are subject to credit risks.

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

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

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The recently enacted Dodd-Frank Wall Street Reform Act may require broad clearing of financial swap transactions through a central counterparty, which may lead to additional margin requirements that could impact our liquidity. Also, in October 2010, the FERC finalized its rulemaking addressing the credit policies of organized electric markets, such as SPP, which may lead to additional margin requirements that could impact our liquidity.

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

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

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

We have defined benefit pension and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

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

Our self-insured costs of health care benefits for eligible employees and costs for retiree health care plans have increased substantially in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Legislation related to health care could also significantly change our benefit programs and costs.

Operational Risks

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

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

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

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

On a periodic basis, or as needed, our utility operations file long-term resource plans with our regulators. These plans are based on numerous assumptions over the relevant planning horizon such as: sales growth, economic activity, costs, regulatory mechanisms, impact of technology on sales and production, customer response and continuation of the existing utility business model. Given the uncertainty in these planning assumptions, there is a risk that the magnitude and timing of resource additions and demand may not coincide. This could lead to under recovery of costs or insufficient resources to meet customer demand.

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

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

As of Dec. 31, 2010, Xcel Energy had approximately $9.3 billion of long-term debt and $0.5 billion of short-term debt and current maturities. Xcel Energy provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy's guarantees limit its exposure to a maximum amount that is stated in the guarantees. As of Dec. 31, 2010, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $155.7 million and $18.0 million of exposure. Xcel Energy also had additional guarantees of $32.5 million at Dec. 31, 2010 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy's ability to contribute equity or make loans to us, or may cause Xcel Energy to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

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

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

We have historically paid quarterly dividends to Xcel Energy. In 2010, 2009 and 2008 we paid $67.1 million, $66.8 million and $61.8 million of dividends to Xcel Energy, respectively. If Xcel Energy's cash requirements increase, our board of directors could decide to increase the dividends we pay to Xcel Energy to help support Xcel Energy's cash needs. This could adversely affect our liquidity.

Public Policy Risks

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

Increased public awareness and concern regarding climate change may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHGs, and federal legislation has been introduced in both houses of Congress. Internationally, other nations have already agreed to regulate emissions of GHGs pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," by 2012. In addition, in 2009, the United States submitted a non-binding GHG emission reduction target of 17 percent compared to 2005 levels pursuant to the Copenhagen Accord. Such legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities are likely to be subject to regulation under climate change laws introduced at either the state or federal level within the next few years.

The EPA has taken steps to regulate GHGs under the CAA. In December 2009, the EPA issued a finding that GHG emissions endanger public health and welfare, and that motor vehicle emissions contribute to the GHGs in the atmosphere. This endangerment finding created a mandatory duty for the EPA to regulate GHGs from light duty motor vehicles. In January 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which are applicable to construction of new power plants or power plant modifications that increase emissions above a certain threshold. The EPA has also announced that it will propose GHG regulations applicable to emissions from existing power plants in July 2011, with final standards to be issued in 2012.

We are also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in Note 12 to the financial statements. While we believe such lawsuits are without merit, an adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Many of the federal and state climate change legislative proposals use a cap and trade policy structure, in which GHG emissions from a broad cross-section of the economy would be subject to an overall cap. Under the proposals, the cap becomes more stringent with the passage of time. The proposals establish mechanisms for GHG sources, such as power plants, to obtain "allowances" or permits to emit GHGs during the course of a year. The sources may use the allowances to cover their own emissions or sell them to other sources that do not hold enough emission allowances for their own operations. Proponents of the cap and trade policy believe it will result in the most cost effective, flexible emission reductions. There are many uncertainties, however, regarding when and in what form climate change legislation or regulation will be enacted. The impact of legislation and regulations, including a cap and trade structure, on us and our customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the United States, any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include, but are not limited to, rules associated with mercury, regional haze, ozone, ash management and cooling water intake systems. The costs of investment to comply with these rules could be substantial. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased the FERC's civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of $1 million per violation per day. In addition, more than 120 electric reliability standards that were historically subject to voluntary compliance are now mandatory and subject to potential financial penalties by NERC or FERC for violations. If a serious reliability incident did occur, it could have a material adverse effect on our operations or financial results.

Macroeconomic Risks

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged economic recession and uncertainty of recovery may result in a sustained lower level of economic activity and uncertainty with respect to energy prices and the capital and commodity markets. A sustained lower level of economic activity may also result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital, which are discussed in greater detail in the capital market risk section above.

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

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

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

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

The insurance industry has also been affected by these events and the availability of insurance covering risks we and our competitors typically insure against may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. For example, wildfire events, particularly in the geographic areas we serve, may cause insurance for wildfire losses to become difficult or expensive to obtain.

A security breach of our information systems could impact the reliability of our generation, transmission and distribution systems and also subject us to financial harm associated with theft or inappropriate release of certain types of information, including, but not limited to system operating information and information regarding our customers and employees. We are unable to quantify the potential impact of such an event, however, such an event could result in significant costs and penalties as well as legal costs.

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

The degree to which we are able to maintain day-to-day operations in response to unforeseen events, potentially through the execution of our business continuity plans, will in part determine the financial impact of certain events on our financial condition and results. It's difficult to predict the magnitude of such events and associated impacts.

Rising energy prices could negatively impact our business.

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

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

Our electric utility business is seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition and results of operations.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Electric Utility Generating Stations:

SPS

Station, Location and Unit	Fuel	Installed	Summer 2010 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,065
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	257
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M.	Natural Gas	1967	118
Moore County-Amarillo, Texas	Natural Gas	1954	46
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	412
Combustion Turbine:			
Carlsbad-Carlsbad, N.M.	Natural Gas	1968	10
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	223
Maddox-Hobbs, N.M.	Natural Gas	1963-1976	58
Riverview-Electric City, Texas	Natural Gas	1973	22
Diesel:			
Tucumcari-Tucumcari, N.M., 2 Units	Diesel	1976-1979	- [(a)]
		Total	4,172

[(a)] This capacity is only available in emergency situations. Therefore, the on-demand net dependable capacity is zero.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2010:

Conductor Miles	
345 KV	6,806
230 KV	9,509
115 KV	11,365
Less than 115 KV	21,130

SPS had 421 electric utility transmission and distribution substations at Dec. 31, 2010.

Item 3 — Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against SPS. After consultation with legal counsel, SPS has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

For a discussion of legal claims and environmental proceedings, see Note 12 to the financial statements. For a discussion of proceedings involving utility rates and other regulatory matters, see Item 1 for Public Utility Regulation, Summary of Recent Federal Regulatory Developments and Note 11 to the financial statements for further discussion.

Item 4 — Reserved

PART II

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

SPS is a wholly owned subsidiary and there is no market for its common equity securities.

SPS has dividend restrictions imposed by its credit facility, FERC rules and state regulatory commissions.

- SPS' credit facility includes a financial covenant that requires the equity-to-total capitalization ratio to be greater than or equal to 35 percent. SPS was in compliance as its equity-to-total capitalization ratio was 50 percent and 51 percent at Dec. 31, 2010 and 2009, respectively.
- Dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.
- State regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy.

The dividends declared during 2010 and 2009 were as follows:

(Thousands of Dollars)	2010	2009
First quarter	$ 16,896	$ 17,374
Second quarter	16,674	16,854
Third quarter	16,292	17,032
Fourth quarter	16,357	17,240

Item 6 — Selected Financial Data

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

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

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

Financial Review

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

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by SPS; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; environmental laws and regulations; actions of accounting regulatory bodies; and the other risk factors listed from time to time by SPS in reports filed with the SEC, including "Risk Factors" in Item 1A of SPS' Form 10-K for the year ended Dec. 31, 2010 and Exhibit 99.01 to SPS' Form 10-K for the year ended Dec. 31, 2010.

Results of Operations

SPS' net income was approximately $78.1 million for 2010, compared with net income of approximately $67.8 million for 2009. The increase is primarily due to electric sales growth, particularly to the commercial and industrial customer class, the reversal of previously established fuel reserves following the approval of certain settlement agreements and lower interest expense, which was partially offset by higher O&M expenses.

Electric Revenues and Margins

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. The design of fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses and, therefore, changes in fuel or purchased power costs can impact earnings. The following table details the electric revenues and margin:

(Millions of Dollars)	2010	2009
Electric revenues	$ 1,613	$ 1,459
Electric fuel and purchased power	(1,024)	(914)
Electric margin	$ 589	$ 545

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

Electric Revenues

(Millions of Dollars)	2010 vs. 2009
Fuel and purchased power cost recovery	$ 117
Fuel cost allocation regulatory accruals	15
Firm wholesale	9
Transmission revenue	8
Retail rate increases (New Mexico)	6
Sales mix and demand revenues	6
Retail sales increase (excluding weather impact)	5
Non-fuel riders	(4)
Other, net	(8)
Total increase in electric revenue	$ 154

Electric Margin

(Millions of Dollars)	2010 vs. 2009
Fuel cost allocation regulatory accruals	$ 15
Firm wholesale	9
Retail rate increase (New Mexico)	6
Sales mix and demand revenues	6
Retail sales increase (excluding weather impact)	5
Non-fuel riders	(4)
Other, net	7
Total increase in base electric margin	$ 44

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased $27.4 million, or 12.4 percent, for 2010 compared to 2009. The following summarizes the components of the changes for the year ended Dec. 31:

(Millions of Dollars)	2010 vs. 2009
Higher plant generation costs	$ 11
Higher employee benefit expenses	9
Higher labor costs	3
Higher contract labor costs	2
Other, net	2
Total increase in operating and maintenance expenses	$ 27

AFUDC — AFUDC increased by approximately $0.5 million for the twelve months of 2010 compared with 2009. This increase was primarily due to larger CWIP balances.

Interest Charges — Interest charges decreased by $7.8 million, or 10.8 percent, for 2010 compared with 2009. The decrease was primarily due to the retirement of long-term debt in March 2009.

Demand Side Management (DSM) Program Expenses — DSM program expenses for 2010 increased by approximately $4.4 million, or 59.9 percent, compared with 2009. The higher expenses are attributable to the continued expansion of programs and regulatory commitments. DSM program expenses are generally recovered in major jurisdictions concurrently through riders and base rates.

Income Taxes — Income tax expense increased by $8.4 million for 2010, compared with 2009. The increase in income tax expense was primarily due to an increase in pretax income and a write-off of tax benefit previously recorded for Medicare Part D subsidies. The effective tax rate was 38.5 percent for 2010, compared with 37.4 percent for 2009. The higher effective tax rate for 2010 was primarily due to the write-off of tax benefit for Medicare Part D subsidies in 2010. Without this write-off, the effective tax rate for 2010 would have been 37.0 percent.

The effective tax rate for 2010 differs from the statutory federal income tax rate, primarily due to state income tax expense and a write-off of tax benefit previously recorded for Medicare Part D subsidies. The effective tax rate for 2009 differs from the statutory federal income tax rate, primarily due to state income tax expense. See Note 6 to the financial statements for further discussion.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

Derivatives, Risk Management and Market Risk

In the normal course of business, SPS is exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. These risks, as applicable to SPS, are discussed in further detail in Note 9 to the financial statements.

Commodity Price Risk — SPS is exposed to commodity price risk in its electric operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in the generation and distribution activities. SPS' risk management policy allows it to manage commodity price risk to the extent such exposure exists.

Short-Term Wholesale and Commodity Trading Risk — SPS conducts an immaterial amount of short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy related instruments. SPS' risk-management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by the policy.

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

At Dec. 31, 2010, a 100-basis-point change in the benchmark rate on SPS' variable rate debt would impact pretax interest expense by approximately $0.5 million annually. See Note 9 to the financial statements for a discussion of SPS' interest rate derivatives.

Credit Risk — SPS is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance of their contractual obligations. SPS maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations. At Dec. 31, 2010, a 10 percent increase or decrease in prices would have no impact on credit exposure.

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

Item 8 — Financial Statements and Supplementary Data

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

See Note 16 to the financial statements for summarized quarterly financial data.

PROJECT 18688

Management Report on Internal Controls Over Financial Reporting

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

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

SPS management assessed the effectiveness of the company's internal control over financial reporting as of Dec. 31, 2010. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we believe that, as of Dec. 31, 2010, the company's internal control over financial reporting is effective based on those criteria.

/s/ C. RILEY HILL
C. Riley Hill
President and Chief Executive Officer
Feb.28, 2011

/s/ DAVID M. SPARBY
David M. Sparby
Vice President and Chief Financial Officer
Feb. 28, 2011

PROJECT 18688

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholder
Southwestern Public Service Company

We have audited the accompanying balance sheets and statements of capitalization of Southwestern Public Service Company (the "Company") as of December 31, 2010 and 2009, and the related statements of income, common stockholder's equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Southwestern Public Service Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
Feb. 28, 2011

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF INCOME
(amounts in thousands of dollars)

	Year Ended Dec. 31,		
	2010	2009	2008
Operating revenues	$ 1,612,990	$ 1,459,223	$ 1,992,774
Operating expenses			
Electric fuel and purchased power	1,023,938	914,350	1,530,999
Other operating and maintenance expenses	249,071	221,681	207,753
Demand side management program expenses	11,625	7,270	8,677
Depreciation and amortization	103,935	104,602	98,657
Taxes (other than income taxes)	40,984	38,503	41,238
Total operating expenses	1,429,553	1,286,406	1,887,324
Operating income	183,437	172,817	105,450
Other income, net	27	264	5,829
Allowance for funds used during construction — equity	4,188	4,082	-
Interest charges and financing costs			
Interest charges — includes other financing costs of $2,635, $2,653 and $2,430, respectively	63,912	71,688	61,090
Allowance for funds used during construction — debt	(3,193)	(2,770)	(2,580)
Total interest charges and financing costs	60,719	68,918	58,510
Income before income taxes	126,933	108,245	52,769
Income taxes	48,866	40,495	20,977
Net income	$ 78,067	$ 67,750	$ 31,792

See Notes to Financial Statements

PROJECT 18688

SOUTHWESTERN PUBLIC SERVICE CO.

STATEMENTS OF CASH FLOWS

(amounts in thousands of dollars)

	Year Ended Dec. 31,		
	2010	2009	2008
Operating activities			
Net income	$ 78,067	$ 67,750	$ 31,792
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	106,207	106,897	103,116
Demand side management program amortization	2,034	1,793	6,942
Deferred income taxes	25,312	30,373	8,423
Amortization of investment tax credits	(341)	(298)	(305)
Allowance for equity funds used during construction	(4,188)	(4,082)	-
Provision for bad debts	3,990	3,765	4,745
Net realized and unrealized hedging and derivative transactions	268	(2,698)	3,234
Changes in operating assets and liabilities:			
Accounts receivable	1,691	11,919	3,419
Accrued unbilled revenues	(4,399)	(7,922)	10,462
Inventories	(2,702)	19,935	(29,739)
Prepayments and other	10,920	(10,558)	2,080
Accounts payable	(17,015)	(5,788)	15,914
Net regulatory assets and liabilities	(20,082)	43,946	34,847
Other current liabilities	3,902	(3,236)	(4,769)
Change in other noncurrent assets	(2,868)	(11,067)	(12,069)
Change in other noncurrent liabilities	(3,466)	(19,218)	6,527
Net cash provided by operating activities	177,330	221,511	184,619
Investing activities			
Utility capital/construction expenditures	(309,408)	(211,866)	(193,501)
Proceeds from the sale of assets	87,823	-	-
Allowance for equity funds used during construction	4,188	4,082	-
Investments in utility money pool arrangement	(204,200)	(990,800)	(247,200)
Receipts from utility money pool arrangement	281,200	1,004,300	156,700
Net cash used in investing activities	(140,397)	(194,284)	(284,001)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	49,000	-	(123,000)
Proceeds from issuance of long-term debt	-	-	246,119
Repayment of long-term debt, including reacquisition premiums	(25,000)	(100,057)	-
Borrowings under utility money pool arrangement	483,200	-	672,700
Repayments under utility money pool arrangement	(483,200)	-	(678,200)
Capital contributions from parent	583	16,243	173,639
Dividends paid to parent	(67,101)	(66,845)	(61,795)
Net cash (used in) provided by financing activities	(42,518)	(150,659)	229,463
Net (decrease) increase in cash and cash equivalents	(5,585)	(123,432)	130,081
Cash and cash equivalents at beginning of year	7,363	130,795	714
Cash and cash equivalents at end of year	$ 1,778	$ 7,363	$ 130,795
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (57,969)	$ (69,619)	$ (59,530)
Cash paid for income taxes, net	(7,277)	(20,118)	(15,735)
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 9,539	$ 12,432	$ 6,243

See Notes to Financial Statements

PROJECT 18688

SOUTHWESTERN PUBLIC SERVICE CO.

BALANCE SHEETS

(amounts in thousands of dollars)

	Dec. 31, 2010	Dec. 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 1,778	$ 7,363
Investments in utility money pool arrangement	-	77,000
Accounts receivable, net	44,871	47,065
Accounts receivable from affiliates	1,610	5,097
Accrued unbilled revenues	110,184	105,785
Inventories	29,849	27,147
Regulatory assets	21,547	16,476
Derivative instruments	7,892	8,926
Deferred income taxes	19,051	32,400
Prepayments and other	5,006	15,927
Total current assets	241,788	343,186
Property, plant and equipment, net	2,401,266	2,260,984
Other assets		
Regulatory assets	283,207	271,417
Derivative instruments	64,734	67,625
Other	10,668	8,783
Total other assets	358,609	347,825
Total assets	$ 3,001,663	$ 2,951,995
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 44,500	$ -
Short-term debt	49,000	-
Accounts payable	134,322	163,253
Accounts payable to affiliates	24,525	14,625
Regulatory liabilities	53,197	65,121
Taxes accrued	19,867	18,209
Accrued interest	12,128	12,371
Dividends payable to parent	16,358	17,240
Derivative instruments	3,601	3,588
Other	21,349	20,125
Total current liabilities	378,847	314,532
Deferred credits and other liabilities		
Deferred income taxes	541,204	529,235
Deferred investment tax credits	2,051	2,392
Regulatory liabilities	134,952	113,742
Asset retirement obligations	21,131	18,757
Derivative instruments	44,991	48,654
Pension and employee benefit obligations	52,280	44,276
Other	10,827	8,450
Total deferred credits and other liabilities	807,436	765,506
Commitments and contingent liabilities		
Capitalization		
Long-term debt	853,267	922,447
Common stock – authorized 200 shares of $1.00 par value; outstanding 100 shares	-	-
Additional paid in capital	693,531	692,948
Retained earnings	270,257	258,409
Accumulated other comprehensive loss	(1,675)	(1,847)
Total common stockholder's equity	962,113	949,510
Total liabilities and equity	$ 3,001,663	$ 2,951,995

See Notes to Financial Statements

PROJECT 18688

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
AND COMPREHENSIVE INCOME

(amounts in thousands of dollars, except share data)

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
	Shares	Par Value				
Balance at Dec. 31, 2007	100	$ -	$ 503,066	$ 289,092	$ (6,005)	$ 786,153
Adoption of new accounting guidance for endorsement split-dollar life insurance, net of tax of $(174)				(276)		(276)
Net income				31,792		31,792
Net derivative instrument fair value changes during the period, net of tax of $253					446	446
Comprehensive income for 2008						32,238
Common dividends declared to parent				(61,449)		(61,449)
Contribution of capital by parent			173,639			173,639
Balance at Dec. 31, 2008	100	$ -	$ 676,705	$ 259,159	$ (5,559)	$ 930,305
Net income				67,750		67,750
Net derivative instrument fair value changes during the period, net of tax of $2,093					3,712	3,712
Comprehensive income for 2009						71,462
Common dividends declared to parent				(68,500)		(68,500)
Contribution of capital by parent			16,243			16,243
Balance at Dec. 31, 2009	100	$ -	$ 692,948	$ 258,409	$ (1,847)	$ 949,510
Net income				78,067		78,067
Net derivative instrument fair value changes during the period, net of tax of $96					172	172
Comprehensive income for 2010						78,239
Common dividends declared to parent				(66,219)		(66,219)
Contribution of capital by parent			583			583
Balance at Dec. 31, 2010	100	$ -	$ 693,531	$ 270,257	$ (1,675)	$ 962,113

See Notes to Financial Statements

PROJECT 18688

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF CAPITALIZATION
(amounts in thousands of dollars)

	Dec. 31, 2010	Dec. 31, 2009
Long-Term Debt		
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	$ 200,000	$ 200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Pollution control obligations, securing pollution control revenue bonds, due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 8.5%	-	25,000
Sept. 1, 2016, 5.75%	57,300	57,300
Unamortized discount	(4,033)	(4,353)
Total	897,767	922,447
Less current maturities	44,500	-
Total long-term debt	$ 853,267	$ 922,447
Common Stockholder's Equity		
Common stock — authorized 200 shares of $1.00 par value; outstanding 100 shares in 2010 and 2009	$ -	$ -
Additional paid in capital	693,531	692,948
Retained earnings	270,257	258,409
Accumulated other comprehensive loss	(1,675)	(1,847)
Total common stockholder's equity	$ 962,113	$ 949,510

See Notes to Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — SPS is principally engaged in the generation, purchase, transmission, distribution and sale of electricity. SPS is subject to regulation by the FERC and state utility commissions. All of SPS' accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

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

SPS has various rate-adjustment mechanisms in place that currently provide for the recovery of natural gas and other electric fuel costs, as well as purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically for any difference between the total amount collected under the clauses and the recoverable costs incurred. Where applicable, under governing state regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets. A summary of significant rate-adjustment mechanisms follows:

- In Texas, SPS recovers fuel and purchased energy costs through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric rates. The Texas retail fuel factors can change up to three times per year based on the projected costs of natural gas. In January 2010, the PUCT approved recovery of certain transmission investments and other transmission costs through the TCRF rider. In New Mexico, the NMPRC has authorized SPS to use a monthly adjustment factor for FPPCAC to recover fuel and purchased power costs, subject to the ongoing NMPRC approval and audits.

- SPS sells firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms.

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

Pursuant to the JOA approved by the FERC, some of the commodity trading margins from SPS are apportioned to NSP-Minnesota and PSCo. Commodity trading activities are not associated with energy produced from SPS' generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. For more information, see Note 9 to the financial statements.

Fair Value Measurements — SPS presents cash equivalents, interest rate derivatives and commodity derivatives at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value, and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts, or internally prepared valuation models to determine fair value.

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

Gains or losses on hedging transactions for the sale of energy or energy-related products are primarily recorded as a component of revenue; hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; and interest rate hedging

transactions are recorded as a component of interest expense.

Cash Flow Hedges — Qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). The accounting for derivatives requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. SPS formally documents all hedging relationships in accordance with this guidance. The documentation includes, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedging transaction. In addition, at inception and on a quarterly basis, SPS formally assesses whether the derivative instruments being used are highly effective in offsetting changes in the cash flows of the hedged items.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction. SPS discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. To test the effectiveness of hedges, a hypothetical hedge is used to mirror all the critical terms of the hedged transaction and the dollar-offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. Gains and losses related to discontinued hedges that were previously deferred in OCI or deferred as regulatory assets or liabilities will remain deferred until the hedged transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, in which case associated deferred amounts are immediately recognized in current earnings.

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

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

For further discussion of SPS' risk management and derivative activities, see Note 9 to the financial statements.

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

SPS records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was 2.7, 2.6 and 2.8 percent for the years ended Dec. 31, 2010, 2009, and 2008, respectively.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in SPS' rate base for establishing utility service rates.

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

Variable Interest Entities — Effective Jan. 1, 2010, SPS adopted new guidance on consolidation of variable interest entities. The guidance requires enterprises to consider the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

Under its purchased power agreements, SPS purchases power from independent power producing entities that own natural gas fueled power plants. Through various mechanisms in certain purchased power agreements, SPS incurs variable fuel costs, and consequently these mechanisms have been determined to create variable interests in the independent power producing entities. Certain independent power producing entities are therefore variable interest entities. SPS has concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

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

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If several designated responsible parties exist, costs are estimated and recorded only for SPS' share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

Legal Costs — Litigation accruals are recorded when it is probable SPS is liable for the costs and the liability can be reasonably estimated. External legal fees related to settlements are expensed as incurred.

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

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

Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 13 to the financial statements. For more information on income taxes, see Note 6 to the financial statements.

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

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

Xcel Energy and its subsidiaries, including SPS, file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. The holding company also allocates its own income tax benefits to its direct subsidiaries based on the relative positive tax liabilities of the subsidiaries.

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

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

Inventory — All inventory is recorded at average cost.

Regulatory Accounting — SPS accounts for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

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

If restructuring or other changes in the regulatory environment occur, SPS may no longer be eligible to apply this accounting treatment and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on SPS' results of operations in the period the write-offs are recorded. See more discussion of regulatory assets and liabilities in Note 13 to the financial statements.

Conservation Programs — SPS has implemented programs in its jurisdictions to assist customers in conserving energy and reducing peak demand on the electric system. These programs include, but are not limited to commercial process efficiency and lighting updates, and residential rebates for participation in air conditioner interruption and energy-efficient appliances.

The costs incurred for some DSM programs are deferred as permitted by the applicable regulatory jurisdiction. For those programs, costs are deferred if it is probable that future revenue, in an amount at least equal to the deferred amount, will be provided to permit recovery of the previously incurred cost, rather than to provide for expected future amounts of similar programs. For incentive programs designed to allow recovery of lost margins and/or conservation performance incentives, recorded revenues are limited to those amounts expected to be collected within twenty four months following the end of the annual period in which they are earned. SPS recovers approved conservation program costs in base rate revenue or through a rider.

Deferred Financing Costs — Other assets included deferred financing costs of approximately $5.9 million and $6.9 million, net of amortization, at Dec. 31, 2010 and 2009, respectively. SPS is amortizing these financing costs over the remaining maturity periods of the related debt.

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

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

The obligation recognized is reduced over the term of the guarantee as SPS is released from risk under the guarantee. Refer to note 10 to the financial statements for specific details of issued guarantees.

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

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

When RECs are acquired in the course of generation or purchased as a result of meeting load obligations, they are recorded as inventory at cost. RECs acquired for trading purposes are recorded as other investments and are also recorded at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. The net margin on sales of RECs for trading purposes is recorded as electric utility operating revenues net of any margin sharing requirements. As a result of certain state regulatory orders, SPS reduces recoverable fuel costs for the value of certain RECs and records the cost of future compliance requirements that are recoverable in future rates as regulatory assets.

Emission Allowances — Emission allowances are recorded at cost, including the annual SO_2 and NOx emission allowance entitlement received at no cost from the EPA. SPS follows the inventory accounting model for all emission allowances. The sales of allowances are included in electric utility operating revenues and the operating activities section of the statements of cash flows.

Reclassifications — Certain prior year amounts have been reclassified to conform to the current year presentation, including amounts related to deferred income taxes, regulatory assets and regulatory liabilities in the balance sheet and statements of cash flows.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2010 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. These reclassifications did not have an impact on net income.

2. Accounting Pronouncements

Consolidation of Variable Interest Entities — In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance affects various elements of consolidation, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. These updates to the ASC were effective for interim and annual periods beginning after Nov. 15, 2009. SPS implemented the guidance on Jan. 1, 2010, and the implementation did not have a material impact on its financial statements. For further information and required disclosures regarding variable interest entities, see Note 12 to the financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (ASU No. 2010-06)*, which updates the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for fair value measurements, transfers between levels of the fair value hierarchy, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 were effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. SPS implemented the portions of the guidance required on Jan. 1, 2010, and the implementation did not have a material impact on its financial statements. For further information and required disclosures, see Note 9 to the financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2010	Dec. 31, 2009
Accounts receivable, net		
Accounts receivable	$ 49,966	$ 51,480
Less allowance for bad debts	(5,095)	(4,415)
	$ 44,871	$ 47,065
Inventories		
Materials and supplies	$ 15,093	$ 15,737
Fuel	14,756	11,410
	$ 29,849	$ 27,147
Property, plant and equipment, net		
Electric plant	$ 3,826,202	$ 3,777,623
Construction work in progress	221,025	95,652
Total property, plant and equipment	4,047,227	3,873,275
Less accumulated depreciation	(1,645,961)	(1,612,291)
	$ 2,401,266	$ 2,260,984

4. Borrowings and Other Financing Instruments

Money Pool — Xcel Energy and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings from the utility subsidiaries between each other. The holding company may make investments in the utility subsidiaries at market-based interest rates. However, the money pool arrangement does not allow the utility subsidiaries to make investments in the holding company.

The following table presents the money pool investments for SPS:

(Millions of Dollars)	Dec. 31, 2010	Dec. 31, 2009
Money pool investments	$ -	$ 77
Weighted average interest rate	N/A	0.36 %
Money pool borrowing limit	$ 100	$ 100

Commercial Paper — SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. The following table presents commercial paper outstanding for SPS:

(Millions of Dollars)	Dec. 31, 2010	Dec. 31, 2009
Commercial paper outstanding	$ 49	$ -
Weighted average interest rate	0.37 %	N/A
Commercial paper borrowing limit	$ 248	$ 248

Credit Facilities — SPS must have revolving credit facilities in place at least equal to the amount of its respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit agreements. All credit facility bank borrowings and outstanding commercial paper reduce the available capacity under the respective credit facilities as presented in the table below. At Dec. 31, 2010 and Dec. 31, 2009, there were no credit facility bank borrowings outstanding.

At Dec. 31, 2010, SPS had the following committed credit facility in effect, in millions of dollars:

Credit Facility	Drawn*	Available	Original Term	Maturity
$ 248	$ 49	$ 199	Five year	December 2011

* Includes outstanding commercial paper and issued and outstanding letters of credit.

The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. SPS has the right to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval.

- The credit facility has one financial covenant requiring that SPS' debt-to-total capitalization ratio be less than or equal to 65 percent. SPS was in compliance as its debt-to-total capitalization ratio was 50 percent and 49 percent at Dec. 31, 2010 and 2009, respectively. If SPS does not comply with the covenant, an event of default may be declared and it not remedied, and any outstanding amounts due under the facility can be declared due by the lender.

- The credit facility has a cross default provision that provides Xcel Energy will be in default on its borrowings under the facility if any of its subsidiaries, comprising more than 15 percent of the consolidated assets of Xcel Energy on a consolidated basis, defaults on any of its indebtedness greater than $50 million.

- The interest rate is based on either the agent bank's prime rate, or the applicable LIBOR plus a borrowing margin as based on SPS' applicable debt rating; this is 35 basis points.

- The commitment fees, also based on long-term credit ratings, are calculated for the unused portion of the credit facility at 8 basis points for SPS.

- At Dec. 31, 2010, SPS had no direct borrowings on this line of credit; however, the credit facility was used to provide back-up support for $49.0 million of commercial paper outstanding. At Dec. 31, 2009, SPS had no direct borrowings on this line of credit and no outstanding commercial paper; however, the credit facility was used to provide back-up support for $10.0 million of letters of credit.

- Xcel Energy plans to syndicate new credit agreements at the Holding Company, NSP-Minnesota, PSCo, SPS and NSP-Wisconsin during the first quarter of 2011 to replace the existing agreements. The total anticipated size of the new credit facilities will be approximately $2.45 billion, of which $300 million is related to SPS.

Certain SPS payments under its pollution control obligations are pledged to secure obligations of the Red River Authority of Texas.

Long-Term Borrowings

In February 2010, SPS redeemed its $25 million pollution control obligations, securing pollution control revenue bonds, due July 1, 2016. During the next five years, SPS has long-term debt maturities of $44.5 million due in 2011.

5. Preferred Stock

SPS has authorized the issuance of preferred stock.

Shares Authorized	Par Value	Shares Outstanding
10,000,000	$ 1.00	None

6. Income Taxes

Medicare Part D Subsidy Reimbursements — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Based on this provision, SPS is subject to additional taxes and is required to reverse previously recorded tax benefits in the period of enactment.

SPS expensed approximately $1.9 million of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. SPS does not expect the $1.9 million of additional tax expense to recur in future periods.

Federal Audit — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. During the first quarter of 2010, the IRS completed an examination of Xcel Energy's federal income tax returns of tax years 2006 and 2007. The IRS did not propose any material adjustments for those tax years. The statute of limitations applicable to Xcel Energy's 2006 federal income tax return expired in August 2010. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expires in September 2011. The IRS commenced an examination of tax years 2008 and 2009 in the third quarter of 2010. As of Dec. 31, 2010, the IRS had not proposed any material adjustments to tax years 2008 and 2009.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2010, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2006. During the second quarter of 2010, the state of Texas completed its audit of tax years 2006 and 2007. No change in tax liability was proposed. As of Dec. 31, 2010, there were no state income tax audits in progress.

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

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

(Millions of Dollars)	Dec. 31, 2010	Dec. 31, 2009
Unrecognized tax benefit - Permanent tax positions	$ 0.2	$ 0.2
Unrecognized tax benefit - Temporary tax positions	4.1	2.7
Unrecognized tax benefit balance	$ 4.3	$ 2.9

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

(Millions of Dollars)	2010	2009	2008
Balance at Jan. 1	$ 2.9	$ 3.5	$ 2.3
Additions based on tax positions related to the current year	1.3	1.4	0.9
Reductions based on tax positions related to the current year	-	-	(0.1)
Additions for tax positions of prior years	0.2	0.8	0.5
Reductions for tax positions of prior years	(0.1)	(0.1)	(0.1)
Settlements with taxing authorities	-	(2.7)	-
Balance at Dec. 31	$ 4.3	$ 2.9	$ 3.5

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

(Millions of Dollars)	Dec. 31, 2010	Dec. 31, 2009
NOL and tax credit carryforwards	$ (0.1)	$ (0.1)

The increase in the unrecognized tax benefit balance of $1.4 million in 2010 was due to the addition of similar uncertain tax positions related to current and prior years' activity. SPS' amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS audit progresses and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits is as follows:

(Millions of Dollars)	2010	2009	2008
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (0.1)	$ (0.3)	$ (0.1)
Interest income (expense) related to unrecognized tax benefits	(0.1)	0.2	(0.2)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (0.2)	$ (0.1)	$ (0.3)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2010, 2009 or 2008.

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

(Millions of Dollars)	2010	2009
Federal NOL carryforward	5.9	5.9
Federal tax credit carryforwards	1.1	0.7
State NOL carryforwards	17.9	9.3
Valuation allowance for state NOL carryforwards	(1.3)	(3.7)

The federal carryforward periods expire between 2021 and 2030. The state carryforward periods expire between 2011 and 2019.

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

	2010		2009		2008	
Federal statutory rate	35.0	%	35.0	%	35.0	%
Increases (decreases) in tax from:						
Regulatory differences - utility plant items	0.2		0.2		3.5	
State income taxes, net of federal income tax benefit	1.8		2.7		4.5	
Resolution of income tax audits and other	0.1		0.2		(2.1)	
Tax credit recognized, net of federal income tax expense	(0.4)		(0.4)		(0.8)	
Change in unrecognized tax benefits	-		(0.2)		0.2	
Previously recognized Medicare Part D subsidies	1.5		-		-	
Other, net	0.3		(0.1)		(0.5)	
Effective income tax rate	38.5	%	37.4	%	39.8	%

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

(Thousands of Dollars)	2010	2009	2008
Current federal tax expense	$ 19,850	$ 6,922	$ 9,810
Current state tax expense	2,669	4,145	1,800
Current change in unrecognized tax expense (benefit)	1,376	(647)	1,249
Deferred federal tax expense	26,050	29,234	9,589
Deferred state tax expense	747	870	109
Deferred change in unrecognized tax expense (benefit)	(1,340)	438	(1,162)
Deferred tax credits	(145)	(169)	(113)
Deferred investment tax credits	(341)	(298)	(305)
Total income tax expense	$ 48,866	$ 40,495	$ 20,977

The components of deferred income tax at Dec. 31 were:

(Thousands of Dollars)	2010	2009	2008
Deferred tax expense excluding items below	$ 25,318	$ 31,740	$ 5,837
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	90	726	2,830
Endorsement split-dollar life insurance - new accounting guidance	-	-	9
Tax benefit allocated to other comprehensive income	(96)	(2,093)	(253)
Deferred tax expense	$ 25,312	$ 30,373	$ 8,423

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

(Thousands of Dollars)	2010	2009
Deferred tax liabilities:		
Difference between book and tax bases of property	$ 483,998	$ 466,009
Employee benefits	53,505	53,047
Other	20,614	16,289
Total deferred tax liabilities	$ 558,117	$ 535,345
Deferred tax assets:		
Unbilled revenue - fuel costs	$ 11,051	$ 10,575
Regulatory liabilities	9,506	485
NOL carryforward	4,482	3,393
Deferred fuel costs	3,668	10,366
Rate refund	2,248	9,605
Bad debts	1,835	1,589
Other	3,174	2,497
Total deferred tax assets	$ 35,964	$ 38,510
Net deferred tax liability	$ 522,153	$ 496,835

7. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement benefit disclosures below generally represent Xcel Energy consolidated information unless specifically identified as being attributable to SPS. Pension and other postretirement benefit disclosures below generally represent Xcel Energy consolidated information unless specifically identified as being attributable to SPS. Consistent with the process for rate recovery of pension and postretirement benefits for its employees, SPS accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy (multiple employer plans). SPS is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, SPS accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for SPS employees.

Xcel Energy, which includes SPS, offers various benefit plans to its employees. At Dec. 31, 2010, SPS had 804 bargaining employees covered under a collective-bargaining agreement, which expires in October 2011.

Effective Jan. 1, 2009, Xcel Energy and SPS adopted new guidance on employers' disclosures about pension and postretirement benefit plan assets. The new guidance expands employers' disclosure requirements for benefit plan assets, including investment policies and strategies, major categories of plan assets, and information regarding fair value measurements consistent with the disclosures for entities' recurring fair value measurements.

The fair value measurements accounting guidance establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring fair value. The three Levels defined by the hierarchy and examples of each Level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs, such as corporate bonds with pricing based on market interest rate curves and recent trades of similarly rated securities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as asset and mortgage backed securities, for which subjective risk-based adjustments to estimated yield and forecasted prepayments are significant inputs.

Pension Benefits

Xcel Energy, which includes SPS, has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee's average pay and social security benefits. Xcel Energy's and SPS' policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

Xcel Energy and SPS base investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the actual historical returns achieved by the asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the portfolio of pension investments is 9.72 percent, which is greater than the current assumption level. The pension cost determination assumes a forecasted mix of investment types over the long-term. Investment returns in 2010 were above the assumed level of 7.79 percent. Investment returns in 2009 were above the assumed level of 8.50 percent while returns in 2008 were below the assumed level of 8.75 percent. Xcel Energy and SPS continually review pension assumptions. In 2011, Xcel Energy will use an investment-return assumption of 7.50 percent.

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

The following table presents the target pension asset allocation for 2010 and 2009:

	2010		2009	
Domestic and international equity securities	24	%	24	%
Long-duration fixed income securities	41		34	
Short-to-intermediate term fixed income securities	11		19	
Alternative investments	17		18	
Cash	7		5	
Total	100	%	100	%

In 2009, Xcel Energy and SPS engaged J.P. Morgan's Pension Advisory Group to evaluate the allocation of the total assets in the master pension trust, taking into consideration the funded status of each individual pension plan. The ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of short-to-intermediate term and long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, pension plan assets that are measured at fair value as of Dec. 31, 2010 and 2009:

	Dec. 31, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ -	$ 109,027	$ -	$ 109,027
Short-term investments	122,643	26,683	-	149,326
Derivatives	-	8,140	-	8,140
Government securities	-	117,522	-	117,522
Corporate bonds	-	641,807	-	641,807
Asset-backed securities	-	-	26,986	26,986
Mortgage-backed securities	-	-	113,418	113,418
Common stock	117,899	-	-	117,899
Private equity investments	-	-	122,223	122,223
Commingled equity and bond funds	-	1,152,386	-	1,152,386
Real estate	-	-	73,701	73,701
Securities lending collateral obligation and other	-	(91,727)	-	(91,727)
Total	$ 240,542	$ 1,963,838	$ 336,328	$ 2,540,708

	Dec. 31, 2009			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ -	$ 221,971	$ -	$ 221,971
Short-term investments	-	324,683	-	324,683
Derivatives	-	11,606	-	11,606
Government securities	-	94,949	-	94,949
Corporate bonds	-	522,403	-	522,403
Asset-backed securities	-	-	47,825	47,825
Mortgage-backed securities	-	-	144,006	144,006
Common stock	89,260	-	-	89,260
Private equity investments	-	-	82,098	82,098
Commingled equity and bond funds	-	1,014,072	-	1,014,072
Real estate	-	-	66,704	66,704
Securities lending collateral obligation and other	-	(170,251)	-	(170,251)
Total	$ 89,260	$ 2,019,433	$ 340,633	$ 2,449,326

The following tables present the changes in Level 3 pension plan assets for the years ended Dec. 31, 2010 and 2009:

(Thousands of Dollars)	Jan. 1, 2010	Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, net	Dec. 31, 2010
Asset-backed securities	$ 47,825	$ (3,678)	$ (17,161)	$ 26,986
Mortgage-backed securities	144,006	(5,376)	(25,212)	113,418
Real estate	66,704	7,100	(103)	73,701
Private equity investments	82,098	(1,032)	41,157	122,223
Total	$ 340,633	$ (2,986)	$ (1,319)	$ 336,328

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, net	Dec. 31, 2009
Asset-backed securities	$ 77,398	$ 48,285	$ (77,858)	$ 47,825
Mortgage-backed securities	166,610	103,470	(126,074)	144,006
Real estate	109,289	(43,207)	622	66,704
Private equity investments	81,034	(5,682)	6,746	82,098
Total	$ 434,331	$ 102,866	$ (196,564)	$ 340,633

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2010	2009
Accumulated Benefit Obligation at Dec. 31	$ 2,865,845	$ 2,676,174
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 2,829,631	$ 2,598,032
Service cost	73,147	65,461
Interest cost	165,010	169,790
Plan amendments	18,739	(35,341)
Actuarial loss	169,203	223,122
Benefit payments	(225,438)	(191,433)
Obligation at Dec. 31	$ 3,030,292	$ 2,829,631
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 2,449,326	$ 2,185,203
Actual return on plan assets	282,688	255,556
Employer contributions	34,132	200,000
Benefit payments	(225,438)	(191,433)
Fair value of plan assets at Dec. 31	$ 2,540,708	$ 2,449,326
Funded Status of Plans at Dec. 31:		
Funded status [a]	$ (489,584)	$ (380,305)
SPS Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 207,981	$ 198,711
Prior service cost	3,906	5,410
Total	$ 211,887	$ 204,121
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	$ 211,887	$ 204,121
SPS accrued benefit liability recorded	33,166	19,607
Measurement date	Dec. 31, 2010	Dec. 31, 2009
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	5.50 %	6.00 %
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

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

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2008 through 2010 for Xcel Energy's pension plans and are not expected to require cash funding in 2011.

Xcel Energy made total pension contributions of $34 million and $200 million during 2010 and 2009, respectively.

- Voluntary contributions were made to the Xcel Energy Pension Plan of $34 million in 2010.
- Voluntary contributions were made to the PSCo Bargaining Pension Plan of $173 million in 2009.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of $27 million in 2009.
- Voluntary contributions were made across three of Xcel Energy's pension plans for $134 million in January 2011. The contribution raised the overall funded status from 84 percent at Dec. 31, 2010 to 88 percent with all other pension assumptions remaining constant.
- Pension funding contributions for 2012, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $175 million.

Plan Amendments — The 2010 increase of the projected benefit obligation for plan amendments is due to a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

Benefit Costs — The components of net periodic pension cost (credit) are:

(Thousands of Dollars)	2010	2009	2008
Service cost	$ 73,147	$ 65,461	$ 62,698
Interest cost	165,010	169,790	167,881
Expected return on plan assets	(232,318)	(256,538)	(274,338)
Amortization of prior service cost	20,657	24,618	20,584
Amortization of net loss	48,315	12,455	11,156
Net periodic pension cost (credit)	$ 74,811	$ 15,786	$ (12,019)
SPS:			
Net periodic pension cost (credit)	$ 5,793	$ (6,644)	$ (10,739)
Significant Assumptions Used to Measure Costs:			
Discount rate	6.00 %	6.75 %	6.25 %
Expected average long-term increase in compensation level	4.00	4.00	4.00
Expected average long-term increase in compensation level	7.79	8.50	8.75

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2011 pension cost calculations will be 7.50 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including SPS, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year.

Xcel Energy, which includes SPS, also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of operating cash flows.

Defined Contribution Plans

Xcel Energy, including SPS, maintains 401(k) and other defined contribution plans that cover substantially all employees. The contributions for SPS were approximately $2.0 million in 2010, $1.4 million in 2009 and $1.2 million in 2008.

Postretirement Health Care Benefits

Xcel Energy, which includes SPS, has a contributory health and welfare benefit plan that provides health care and death benefits to most retirees. Employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Nonbargaining employees of the former NCE, who retired after June 30, 2003, are eligible to participate in the health care program with no employer subsidy.

In 1993, Xcel Energy and SPS adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized APBO on a straight-line basis over 20 years. Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs under the new guidance.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy and SPS base investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. The assets are invested in a portfolio according to Xcel Energy's and SPS' return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

The following tables present, for each of the fair value hierarchy levels, postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2010 and 2009:

	Dec. 31, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 72,573	$ 76,352	$ -	$ 148,925
Derivatives	-	13,632	-	13,632
Government securities	-	3,402	-	3,402
Corporate bonds	-	70,752	-	70,752
Asset-backed securities	-	-	2,585	2,585
Mortgage-backed securities	-	-	19,212	19,212
Preferred stock	-	507	-	507
Commingled equity and bond funds	-	102,962	-	102,962
Securities lending collateral obligation and other	-	70,253	-	70,253
Total	$ 72,573	$ 337,860	$ 21,797	$ 432,230

	Dec. 31, 2009			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ -	$ 165,291	$ -	$ 165,291
Short-term investments	-	2,226	-	2,226
Derivatives	-	5,937	-	5,937
Government securities	-	1,538	-	1,538
Corporate bonds	-	60,416	-	60,416
Asset-backed securities	-	-	8,293	8,293
Mortgage-backed securities	-	-	47,078	47,078
Preferred stock	-	540	-	540
Commingled equity and bond funds	-	89,296	-	89,296
Securities lending collateral obligation and other	-	4,074	-	4,074
Total	$ -	$ 329,318	$ 55,371	$ 384,689

The following tables present the changes in Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2010:

(Thousands of Dollars)	Jan. 1, 2010	Realized and Unrealized Gains	Purchases, Issuances, and Settlements, net	Dec. 31, 2010
Asset-backed securities	$ 8,293	$ 1,814	$ (7,522)	$ 2,585
Mortgage-backed securities	47,078	14,715	(42,581)	19,212

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains	Purchases, Issuances, and Settlements, net	Dec. 31, 2009
Asset-backed securities	$ 8,705	$ 1,029	$ (1,441)	$ 8,293
Mortgage-backed securities	69,988	3,022	(25,932)	47,078

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2010	2009
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 728,902	$ 794,597
Service cost	4,006	4,665
Interest cost	42,780	50,412
Medicare subsidy reimbursements	5,423	3,226
Plan amendments	-	(27,407)
Plan participants' contributions	14,315	13,786
Actuarial loss (gain)	68,126	(47,446)
Benefit payments	(68,647)	(62,931)
Obligation at Dec. 31	$ 794,905	$ 728,902
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 384,689	$ 299,566
Actual return on plan assets	53,430	72,101
Plan participants' contributions	14,315	13,786
Employer contributions	48,443	62,167
Benefit payments	(68,647)	(62,931)
Fair value of plan assets at Dec. 31	$ 432,230	$ 384,689
Funded Status of Plans at Dec. 31:		
Funded status	$ (362,675)	$ (344,213)
Current liabilities	(5,392)	(2,240)
Noncurrent liabilities	(357,283)	(341,973)
Net postretirement amounts recognized on consolidated balance sheets	$ (362,675)	$ (344,213)
SPS Amounts Not Yet Recognized as Components of Net Periodic Benefit Credit:		
Net gain	$ (9,455)	$ (6,914)
Prior service credit	(182)	(233)
Transition obligations	3,214	4,883
Total	$ (6,423)	$ (2,264)
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets and liabilities	$ (6,423)	$ (2,264)
SPS accrued benefit liability recorded	10,636	14,590
Measurement date	Dec. 31, 2010	Dec. 31, 2009
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	5.50 %	6.00 %
Mortality table	RP 2000	RP 2000
Health care costs trend rate - inital	6.50 %	6.80 %

Effective Dec. 31, 2010, the ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached increased from three years to eight years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects on SPS:

(Thousands of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
APBO	$ 98,812	$ (76,175)
Service and interest components	5,006	(4,193)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy, which includes SPS, contributed $48.4 million during 2010 and $62.2 million during 2009 and expects to contribute approximately $40.5 million during 2011.

Plan Amendments — No amendments occurred during 2010 to the Xcel Energy health and welfare benefit plan.

Benefit Costs — The components of net periodic postretirement benefit cost are:

(Thousands of Dollars)	2010	2009	2008
Service cost	$ 4,006	$ 4,665	$ 5,350
Interest cost	42,780	50,412	51,047
Expected return on plan assets	(28,529)	(22,775)	(31,851)
Amortization of transition obligation	14,444	14,444	14,577
Amortization of prior service cost	(4,932)	(2,726)	(2,175)
Amortization of net loss	11,643	19,329	11,498
Net periodic postretirement benefit cost	$ 39,412	$ 63,349	$ 48,446
SPS:			
Net periodic postretirement benefit cost recognized	$ 3,601	$ 5,000	$ 3,484
Significant Assumptions Used to Measure Costs:			
Discount rate	6.00 %	6.75 %	6.25 %
Expected average long-term rate of return on assets (before tax)	7.50	7.50	7.50

Projected Benefit Payments — The following table lists the projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2011	$ 254,426	$ 59,752	$ 4,770	$ 54,982
2012	247,156	60,230	5,126	55,104
2013	249,908	60,607	5,475	55,132
2014	257,886	61,833	5,773	56,060
2015	259,978	63,184	6,061	57,123
2016-2020	1,338,658	325,154	34,115	291,039

8. Other Income, Net

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

(Thousands of Dollars)	2010	2009	2008
Interest income	$ 250	$ 671	$ 4,874
Other nonoperating income	57	68	330
Insurance policy (expenses) income	(280)	(475)	673
Other nonoperating expenses	-	-	(48)
Other income, net	$ 27	$ 264	$ 5,829

9. Derivative Instruments and Fair Value Measurements

SPS may enter into derivative instruments, including forward contracts, futures, swaps and options, to reduce risk in connection with changes in interest rates and electric utility commodity prices.

Short-Term Wholesale and Commodity Trading Risk — SPS conducts an immaterial amount of short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy related instruments. SPS' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by the policy.

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

At Dec. 31, 2010, accumulated other comprehensive losses related to interest rate derivatives included $0.2 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings. Accumulated other comprehensive losses related to interest rate derivatives reclassified into earnings during the year ended Dec. 31, 2010 and Dec. 31, 2009 were $0.3 million and 5.8 million, respectively.

During the fourth quarter of 2009, SPS settled a $25 million notional value interest rate swap. The interest rate swap was not designated as a hedging instrument, and as such, $2.5 million of changes in fair value of the swap were recorded to earnings for the swap during the year ended Dec. 31, 2009.

Commodity Derivatives — SPS may enter into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products. At Dec. 31, 2010 and Dec. 31, 2009, SPS held no commodity derivatives. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

The following table shows the major components of derivative instruments valuation in the balance sheets:

	Dec. 31, 2010		Dec. 31, 2009	
(Thousands of Dollars)	Derivative Instruments - Assets	Derivative Instruments - Liabilities	Derivative Instruments - Assets	Derivative Instruments - Liabilities
Long-term purchased power agreements	$ 72,626	$ 48,592	$ 76,551	$ 52,242

In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, SPS began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate cash flow hedges on SPS' accumulated other comprehensive income, included as a component of common stockholder's equity, is detailed in the following tables:

(Thousands of Dollars)	2010	2009	2008
Accumulated other comprehensive loss related to cash flow hedges at Jan 1	$ (1,847)	$ (5,559)	$ (6,005)
After-tax net unrealized gains related to derivatives accounted for as hedges	-	-	71
After-tax net realized losses on derivative transactions reclassified into earnings	172	3,712	375
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (1,675)	$ (1,847)	$ (5,559)

Fair Value Measurements

SPS had no derivative instruments measured at fair value on a recurring basis as of Dec. 31, 2010 and Dec. 31, 2009.

10. Financial Instruments

The estimated Dec. 31 fair values of SPS' recorded financial instruments are as follows:

(Thousands of Dollars)	2010 Carrying Amount	2010 Fair Value	2009 Carrying Amount	2009 Fair Value
Other investments	$ 246	$ 246	$ 263	$ 263
Long-term debt, including current portion	897,767	989,789	922,447	977,029

The fair values of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. The fair value of SPS' long-term investments are estimated based on quoted market prices for those or similar investments. The fair value of SPS' long-term debt is estimated based on the quoted market prices for the same or similar issues or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2010 and 2009. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair value may differ significantly.

Guarantees — In connection with its sale agreement, SPS provides for indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction.

(Millions of Dollars)	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
Guarantee of indemnification obligations of Lubbock under an asset purchase agreement	$ 87	[a]	Continuing	[a]	N/A

[a] SPS has provided indemnification to Lubbock for losses arising out of any breach of the representations, warranties and covenants under the related asset purchase agreement and for losses arising out of certain other matters, including pre-closing unknown liabilities. The indemnification provisions are capped at the purchase price, $87 million, in the aggregate. As of Dec. 31, 2010, no claims have been made. The indemnification provisions for most representations and warranties expire 12 months after the closing date. Certain representations and warranties, including those having to do with transaction authorization survive indefinitely. The indemnification for covenants survives until the applicable covenant is performed. See Note 17 to the financial statements for further discussion.

Letters of Credit

SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2010, there were no letters of credit outstanding. At Dec. 31, 2009, there were $10.0 million of letters of credit outstanding. The contract amounts of these letters of credit approximate their fair values and are subject to fees determined in the marketplace.

11. Rate Matters

Pending and Recently Concluded Regulatory Proceedings — PUCT

Base Rate

Texas Retail Base Rate Case — In May 2010, SPS filed an electric rate case in Texas seeking an annual base rate increase of approximately $71.5 million inclusive of franchise fees. On a net basis, the request seeks to increase customer bills by approximately $53.4 million or 7 percent. The rate filing is based on a 2009 test year adjusted for known and measurable changes, a requested ROE of 11.35 percent, an electric rate base of $1.031 billion and an equity ratio of 51.0 percent. The filing with the PUCT also includes a request to reconcile SPS' fuel and purchased power costs for calendar years 2008 and 2009. As of Dec. 31, 2009, SPS had a fuel cost under-recovery of approximately $3.3 million.

In November 2010, SPS filed an update to the cost of service to reflect the impact on Texas retail rates, primarily resulting from its sale of Lubbock facilities. The total request was reduced to approximately $63.7 million and the net request $47.6 million.