XCEL ENERGY INC
Form 10-Q
April 30, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2009

or

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

Commission File Number: 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall Minneapolis, Minnesota	**55401**
(Address of principal executive offices)	(Zip Code)

(612) 330-5500

(Registrant s telephone number, including area code)

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 requirement for the past 90 days. xYes oNo

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). oYes oNo

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 x
Accelerated filer £
Non-accelerated filer £ (Do not check if 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 Exchange Act). £Yes xNo

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at April 28, 2009**
Common Stock, $2.50 par value	455,663,348 shares

Table of Contents

TABLE OF CONTENTS

This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado, a Colorado corporation (PSCo); and Southwestern Public Service Company, a New Mexico corporation (SPS). Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

Table of Contents

PART I FINANCIAL INFORMATION

Item 1 FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(amounts in thousands, except per share data)

	Three Months Ended March 31, 2009	2008
Operating revenues		
Electric	$ 1,886,557	$ 1,973,314
Natural gas	788,676	1,034,127
Other	20,309	20,947
Total operating revenues	2,695,542	3,028,388
Operating expenses		
Electric fuel and purchased power	924,748	1,088,080
Cost of natural gas sold and transported	591,765	823,127
Cost of sales other	5,366	5,453
Other operating and maintenance expenses	471,894	461,020
Conservation and demand side management program expenses	45,219	35,570
Depreciation and amortization	208,715	205,607
Taxes (other than income taxes)	77,038	79,413
Total operating expenses	2,324,745	2,698,270
Operating income	370,797	330,118
Interest and other income, net	2,352	8,374
Allowance for funds used during construction equity	18,227	14,220
Interest charges and financing costs		
Interest charges includes other financing costs of $5,038 and $4,991, respectively	141,803	132,171
Allowance for funds used during construction debt	(10,228)	(9,527)
Total interest charges and financing costs	131,575	122,644
Income from continuing operations before income taxes and equity earnings	259,801	230,068
Income taxes	87,125	76,584
Equity earnings of unconsolidated subsidiaries	3,142	510
Income from continuing operations	175,818	153,994
Loss from discontinued operations, net of tax	(1,751)	(877)
Net income	174,067	153,117
Dividend requirements on preferred stock	1,060	1,060
Earnings available to common shareholders	$ 173,007	$ 152,057
Weighted average common shares outstanding:		
Basic	455,192	429,563

Diluted		455,952		434,853
Earnings per average common share:				
Basic	$	0.38	$	0.35
Diluted		0.38		0.35
Cash dividends declared per common share		0.24		0.23

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(amounts in thousands of dollars)

	Three Months Ended March 31, 2009	2008
Operating activities		
Net income	$ 174,067	$ 153,117
Remove loss from discontinued operations	1,751	877
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	219,928	226,271
Nuclear fuel amortization	19,290	13,388
Deferred income taxes	44,638	87,361
Amortization of investment tax credits	(1,738)	(1,948)
Allowance for equity funds used during construction	(18,227)	(14,220)
Equity earnings of unconsolidated subsidiaries	(3,142)	(510)
Dividends from equity method investees	6,015	
Share-based compensation expense	9,337	5,774
Net realized and unrealized hedging and derivative transactions	37,097	22,719
Changes in operating assets and liabilities:		
Accounts receivable	114,182	(11,920)
Accrued unbilled revenues	223,906	138,410
Inventories	215,901	106,477
Recoverable purchased natural gas and electric energy costs	7,988	(78,192)
Other current assets	(5,207)	7,053
Accounts payable	(239,175)	(1,692)
Net regulatory assets and liabilities	28,376	11,195
Other current liabilities	28,107	(65,915)
Change in other noncurrent assets	192	(24,359)
Change in other noncurrent liabilities	(19,609)	1,370
Operating cash flows used in discontinued operations	(31,129)	(25,774)
Net cash provided by operating activities	812,548	549,482
Investing activities		
Utility capital/construction expenditures	(477,736)	(489,775)
Allowance for equity funds used during construction	18,227	14,220
Purchase of investments in external decommissioning fund	(396,527)	(227,987)
Proceeds from the sale of investments in external decommissioning fund	395,815	217,139
Nonregulated capital expenditures and asset acquisitions	(102)	(124)
Investment in WYCO Development LLC	(14,170)	(23,026)
Change in restricted cash		757
Other investments	1,249	519
Net cash used in investing activities	(473,244)	(508,277)
Financing activities		
Repayment of short-term borrowings, net	(17,235)	(710,643)
Proceeds from issuance of long-term debt		893,021
Repayment of long-term debt, including reacquisition premiums	(167,905)	(972)
Proceeds from issuance of common stock	1,270	1,564
Dividends paid	(101,744)	(99,679)
Net cash (used in) provided by financing activities	(285,614)	83,291
Net increase in cash and cash equivalents	53,690	124,496
Net (decrease) increase in cash and cash equivalents discontinued operations	(1,573)	225
Cash and cash equivalents at beginning of year	249,198	51,120
Cash and cash equivalents at end of quarter	$ 301,315	$ 175,841
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (152,517)	$ (123,368)
Cash (paid) received for income taxes (net of refunds received)	(2,761)	1,092
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 30,008	$ 29,119
Supplemental disclosure of non-cash financing transactions:		
Issuance of common stock for reinvested dividends and 401(k) plans	$ 26,973	$ 34,578

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(amounts in thousands of dollars)

	March 31, 2009	Dec. 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 301,315	$ 249,198
Accounts receivable, net	786,599	900,781
Accrued unbilled revenues	519,573	743,479
Inventories	450,808	666,709
Recoverable purchased natural gas and electric energy costs	24,029	32,843
Derivative instruments valuation	67,907	101,972
Prepayments and other	238,368	263,906
Current assets held for sale and related to discontinued operations	63,711	56,641
Total current assets	2,452,310	3,015,529
Property, plant and equipment, net	17,947,476	17,688,720
Other assets		
Nuclear decommissioning fund and other investments	1,179,246	1,232,081
Regulatory assets	2,349,506	2,357,279
Prepaid pension asset	18,154	15,612
Derivative instruments valuation	325,458	325,688
Other	154,355	142,130
Noncurrent assets held for sale and related to discontinued operations	201,756	181,456
Total other assets	4,228,475	4,254,246
Total assets	$ 24,628,261	$ 24,958,495
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 459,257	$ 558,772
Short-term debt	438,015	455,250
Accounts payable	857,671	1,120,324
Taxes accrued	281,028	220,542
Accrued interest	143,497	168,632
Dividends payable	109,184	108,838
Derivative instruments valuation	56,593	75,539
Other	333,312	331,419
Current liabilities held for sale and related to discontinued operations	3,031	6,929
Total current liabilities	2,681,588	3,046,245
Deferred credits and other liabilities		
Deferred income taxes	2,801,822	2,792,560
Deferred investment tax credits	103,978	105,716
Regulatory liabilities	1,184,992	1,194,596
Asset retirement obligations	1,152,096	1,135,182
Derivative instruments valuation	344,389	340,802
Customer advances	318,533	323,445
Pension and employee benefit obligations	1,020,772	1,030,532
Other	178,752	168,352
Noncurrent liabilities held for sale and related to discontinued operations	20,973	20,656
Total deferred credits and other liabilities	7,126,307	7,111,841
Commitments and contingent liabilities		
Capitalization:		
Long-term debt	7,666,304	7,731,688
Preferred stockholders equity authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800	104,980	104,980
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: March 31, 2009 455,256,231; Dec. 31, 2008 453,791,770	7,049,082	6,963,741
Total liabilities and equity	$ 24,628,261	$ 24,958,495

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (UNAUDITED)

(amounts in thousands)

	Common Stock Issued		Additional	Retained	Accumulated Other	Total Common
	Shares	Par Value	Paid In Capital	Earnings	Comprehensive Income (Loss)	Stockholders Equity
Three Months Ended March 31, 2009 and 2008						
Balance at Dec. 31, 2007	428,783	$ 1,071,957	$ 4,286,917	$ 963,916	$ (21,788)	$ 6,301,002
EITF 06-4 adoption, net of tax of $(1,038)				(1,640)		(1,640)
Net income				153,117		153,117
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(635)					(189)	(189)
Net derivative instrument fair value changes during the period, net of tax of $(1,790)					(5,626)	(5,626)
Comprehensive income for the period						147,302
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(99,016)		(99,016)
Issuances of common stock	1,729	4,324	52			4,376
Share-based compensation			6,084			6,084
Balance at March 31, 2008	430,512	$ 1,076,281	$ 4,293,053	$ 1,015,317	$ (27,603)	$ 6,357,048
Balance at Dec. 31, 2008	453,792	$ 1,134,480	$ 4,695,019	$ 1,187,911	$ (53,669)	$ 6,963,741
Net income				174,067		174,067
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $254					369	369
Net derivative instrument fair value changes during the period, net of tax of $801					1,200	1,200
Unrealized loss marketable securities, net of tax of $(64)					(96)	(96)
Comprehensive income for the period						175,540
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(108,447)		(108,447)
Issuances of common stock	1,464	3,661	8,718			12,379
Share-based compensation			6,929			6,929
Balance at March 31, 2009	455,256	$ 1,138,141	$ 4,710,666	$ 1,252,471	$ (52,196)	$ 7,049,082

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of March 31, 2009 and Dec. 31, 2008; the results of its operations and changes in stockholders equity for the three months ended March 31, 2009 and 2008; and its cash flows for the three months ended March 31, 2009 and 2008. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The Dec. 31, 2008 balance sheet information has been derived from the audited 2008 financial statements. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2008, filed with the SEC on Feb. 27, 2009. Due to the seasonality of Xcel Energy s electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

Except to the extent updated or described below, the significant accounting policies set forth in Note 1 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2008, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Reclassifications Conservation and demand side management (DSM) program expenses were reclassified as a separate item. Previously these costs were included in other operating and maintenance expenses and depreciation and amortization on the consolidated statements of income. These reclassifications did not have an impact on total operating expenses.

2. Accounting Pronouncements

Recently Adopted

Business Combinations (Statement of Financial Accounting Standards (SFAS) No. 141 (revised 2007)) In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. Xcel Energy implemented SFAS No. 141(R) on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Noncontrolling Interests in Consolidated Financial Statements, an Amendment of Accounting Research Bulletin (ARB) No. 51 (SFAS No. 160) In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent s equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. SFAS No. 160 was effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy implemented SFAS No. 160 on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (SFAS No. 161) In March 2008, the FASB issued SFAS No. 161, which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity s financial position, financial performance and cash flows. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures including objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. SFAS No. 161 was effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008. Xcel Energy implemented SFAS No. 161 on Jan. 1, 2009, and the implementation did not have a material

Table of Contents

impact on its consolidated financial statements. For further discussion and SFAS No. 161 required disclosures, see Note 10 to the consolidated financial statements.

Recently Issued

Employers Disclosures about Postretirement Benefit Plan Assets (FASB Staff Position (FSP) FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which amends SFAS No. 132 (revised 2003), *Employers Disclosures about Pensions and Other Postretirement Benefits,* to expand an employer s required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 132(R)-1 to have a material impact on its consolidated financial statements.

Interim Disclosures about Fair Value of Financial Instruments (FSP FAS 107-1 and Accounting Principles Board (APB) 28-1) In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, which amends SFAS No. 107*, Disclosures About Fair Value of Financial Instruments*, and APB Opinion No. 28, *Interim Financial Reporting*, to require disclosures regarding the fair value of financial instruments in interim financial statements. In addition, entities are required to disclose the method and significant assumptions used to estimate the fair value of financial instruments. FSP FAS 107-1 and APB 28-1 are effective for interim periods ending after June 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 107-1 and APB 28-1 to have a material impact on its consolidated financial statements.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly (FSP FAS 157-4) In April 2009, the FASB issued FSP FAS 157-4, which provides additional guidance for estimating fair value in accordance with SFAS No. 157, *Fair Value Measurements*, when the volume and level of market activity for an asset or liability have significantly decreased. FSP FAS 157-4 emphasizes that even if there has been a significant decrease in the volume and level of market activity for the asset or liability, fair value still represents the exit price in an orderly transaction between market participants. FSP FAS 157-4 is effective for interim and annual periods ending after June 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 157-4 to have a material impact on its consolidated financial statements.

Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2) In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. FSP FAS 115-2 and FAS 124-2 is effective for interim and annual periods ending after June 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 115-2 and FAS 124-2 to have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2009	Dec. 31, 2008
Accounts receivable, net:		
Accounts receivable	$ 850,184	$ 965,020
Less allowance for bad debts	(63,585)	(64,239)
	$ 786,599	$ 900,781
Inventories:		
Materials and supplies	$ 161,495	$ 158,709
Fuel	181,131	227,462
Natural gas	108,182	280,538
	$ 450,808	$ 666,709
Property, plant and equipment, net:		
Electric plant	$ 21,907,421	$ 21,601,094
Natural gas plant	3,031,950	3,004,088
Common and other property	1,519,695	1,497,162
Construction work in progress	1,814,166	1,832,022
Total property, plant and equipment	28,273,232	27,934,366
Less accumulated depreciation	(10,595,601)	(10,501,266)
Nuclear fuel	1,644,708	1,611,193
Less accumulated amortization	(1,374,863)	(1,355,573)
	$ 17,947,476	$ 17,688,720

Table of Contents

4. Discontinued Operations

Results of operations for divested businesses and the results of businesses held for sale are reported, for all periods presented, as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale have been reclassified to assets and liabilities held for sale in the consolidated balance sheets. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets associated with temporary differences and net operating loss (NOL) and tax credit carry forwards that will be deductible in future years.

The major classes of assets and liabilities held for sale and related to discontinued operations are as follows:

(Thousands of Dollars)		**March 31, 2009**		**Dec. 31, 2008**
Cash	$	9,072	$	10,645
Accounts receivable, net		212		209
Deferred income tax benefits		18,531		39,422
Other current assets		35,896		6,365
Current assets held for sale and related to discontinued operations	$	63,711	$	56,641
Deferred income tax benefits	$	171,731	$	150,912
Other noncurrent assets		30,025		30,544
Noncurrent assets held for sale and related to discontinued operations	$	201,756	$	181,456
Accounts payable	$	806	$	760
Other current liabilities		2,225		6,169
Current liabilities held for sale and related to discontinued operations	$	3,031	$	6,929
Noncurrent liabilities held for sale and related to discontinued operations	$	20,973	$	20,656

5. Income Taxes

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) Xcel Energy files a consolidated federal income tax return and state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns.

In the first quarter of 2008, the Internal Revenue Service (IRS) completed an examination of Xcel Energy s federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. Tax year 2004 is the earliest open year and the statute of limitations applicable to Xcel Energy s 2004 federal income tax return remains open until Dec. 31, 2009. In the third quarter of 2008, the IRS commenced an examination of tax years 2006 and 2007. As of March 31, 2009, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

In the first quarter of 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an income tax audit through tax year 2005. No material adjustments were proposed for these state audits. As of March 31, 2009, Xcel Energy s earliest open tax years in which an audit can be initiated by state taxing authorities in its major operating jurisdictions are as follows: Colorado-2004, Minnesota-2004, Texas-2004 and Wisconsin-2004. There currently are no state income tax audits in progress.

The amount of unrecognized tax benefits reported in continuing operations was $37.7 million on March 31, 2009 and $35.5 million on Dec. 31, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $6.6 million on both March 31, 2009 and Dec. 31, 2008. These unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryovers reported in continuing operations of $8.1 million on March 31, 2009 and $13.1 million on Dec. 31, 2008 and NOL and tax credit carryovers reported in discontinued operations of $25.7 million on March 31, 2009 and $26.5 million on Dec. 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $9.8 million and $9.2 million of tax positions on March 31, 2009 and Dec. 31, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $27.9 million and $26.3 million of tax positions on March 31, 2009 and Dec. 31, 2008, respectively, for which the ultimate deductibility is highly certain but

Table of Contents

for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The increase in the unrecognized tax benefit balance reported in continuing operations of $2.2 million from Dec. 31, 2008 to March 31, 2009, was due to the addition of similar uncertain tax positions related to ongoing activity. Xcel Energy s amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the IRS audit progresses and when 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 liability for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryovers. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the first quarter of 2009 was $0.3 million. The amount reported within interest charges related to unrecognized tax benefits in continuing operations in the first quarter of 2008 reduced interest expense by $1.2 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $2.2 million on March 31, 2009 and $1.9 million on Dec. 31, 2008. The amount reported within interest charges related to unrecognized tax benefits in discontinued operations in both the first quarter of 2009 and the first quarter of 2008 reduced interest expense by $0.2 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $1.7 million on March 31, 2009 and $1.5 million on Dec. 31, 2008.

No amounts were accrued for penalties as of March 31, 2009 and Dec. 31, 2008.

6. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 16 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2008 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference. The following section includes unresolved proceedings that are material to Xcel Energy s financial position.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings   Minnesota Public Utilities Commission (MPUC)

Base Rate

NSP-Minnesota Electric Rate Case On Nov. 3, 2008, NSP-Minnesota filed a request with the MPUC to increase Minnesota electric rates by $156 million annually, or 6.05 percent. The request is based on a 2009 forecast test-year, an electric rate base of $4.1 billion, a requested return on equity (ROE) of 11.0 percent and an equity ratio of 52.5 percent.

In December 2008, the MPUC approved an interim rate increase of $132 million, or 5.12 percent, effective Jan. 2, 2009. The primary difference between interim rate levels approved and NSP-Minnesota s request of $156 million is due to a previously authorized ROE of 10.54 percent and NSP-Minnesota s requested ROE of 11.0 percent.

On April 7, 2009, intervenors submitted direct testimony. The Office of Energy Security (OES) recommended a revenue increase of $72 million, based on a ROE of 10.88 percent and an equity ratio of 52.5 percent. In addition, the OES recommendation reflected the following adjustments:

- Recognition of a 10 year life extension of the Prairie Island nuclear generating facility, resulting in a decrease of approximately $40 million in depreciation and decommissioning expenses and rejection of NSP-Minnesota s proposed nuclear rate stability plan. These adjustments reduce NSP-Minnesota s overall revenue deficiency while at the same time reducing expense accruals by $40 million.
- An adjustment for increased sales, which reduced the request by $12.3 million, a $7 million reduction in short-term capacity expenses, a decrease in overall salaries of $4.8 million, and chemical commodity cost decreases of $1.6 million.

The Office of the Attorney General (OAG) recommended recognition of depreciation and decommissioning cost decreases resulting from the Prairie Island life extension in the current proceeding and rejection of the proposed nuclear rate stability plan. However, the OAG did not recommend a specific reduction in revenue requirements. The OAG also proposed a fuel clause adjustment (FCA) incentive through a 3 percent cap on base fuel costs and requested that any approved increase in rates be applied equally to all classes of customers.

Other parties to the proceeding (Large Customer Group, Minnesota Chamber of Commerce, Suburban Rate Authority, the Customer Group) addressed several non-revenue requirements issues, including FCA reporting and accountability, class cost of service and rate design, and potential changes to NSP-Minnesota s quality of service metrics.

A final decision from the MPUC is expected in the third quarter of 2009. The following procedural schedule has been established:

- NSP-Minnesota rebuttal testimony on May 5, 2009;
- State agency and intervenor surrebuttal testimony on May 26, 2009; and
- Evidentiary hearings are scheduled for June 2-9, 2009.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider In November 2006, the MPUC approved a TCR rider pursuant to legislation, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. In December 2007, NSP-Minnesota filed adjustments to the TCR rate factors and implemented a rider to recover $18.5 million beginning Jan. 1, 2008. In March 2008, the MPUC approved the 2008 rider but required certain procedural changes for future TCR filings if costs are disputed. On Oct. 30, 2008, NSP-Minnesota submitted its proposed TCR rate factors, seeking to recover $14 million in 2009. A portion of amounts previously collected through the TCR rider prior to 2009 has been included for recovery in the NSP-Minnesota electric rate case described above. MPUC approval is pending.

Renewable Energy Standard (RES) Rider In March 2008, the MPUC approved an RES rider to recover the costs for utility-owned projects implemented in compliance with the RES, and the RES rider was implemented on April 1, 2008. Under the rider, NSP-Minnesota could recover up to approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100 megawatt (MW) wind project, subject to true-up. In 2008, NSP-Minnesota submitted the RES rider for recovery of approximately $22 million in 2009 attributable to the Grand Meadow wind farm. On Feb. 12, 2009, the MPUC approved the rider request but required that the issue of whether these costs should be moved to base rates in the currently pending electric rate case or left in the rider, as NSP-Minnesota has proposed, to be addressed through supplemental testimony in the rate case.

Metropolitan Emissions Reduction Project (MERP) Rider On Oct. 1, 2008, NSP-Minnesota filed a proposed MERP rider for 2009 designed to recover costs related to MERP environmental improvement projects. Under this rider, NSP-Minnesota proposes to recover $114 million in 2009, an increase of approximately $23 million over 2008. New rates went into effect automatically on Jan. 1, 2009, as stipulated. MPUC approval is still pending.

Annual Automatic Adjustment Report for 2008 In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, $848.5 million in fuel and purchased energy costs, including $258.8 million of Midwest Independent Transmission System Operator, Inc. (MISO) charges, were recovered from Minnesota electric customers through the FCA. In addition, approximately $680 million of purchased natural gas and transportation costs were recovered through the purchased gas adjustment. The 2008 annual automatic adjustment reports are pending initial comments, scheduled for June 2009, and MPUC action.

MISO Ancillary Service Market (ASM) Cost Recovery On May 9, 2008, NSP-Minnesota and several other Minnesota electric utilities filed jointly for MPUC regulatory approval to recover ASM costs through the Minnesota FCA cost recovery mechanism. On March 17, 2009, the MPUC issued an order approving interim FCA recovery of these charges, subject to refund, and required NSP-Minnesota to make quarterly filings addressing the costs and benefits resulting from ASM participation, and a one time compliance filing in February 2010 that demonstrates that there were benefits to ratepayers of the ASM market after one year of operation. No party requested reconsideration of the MPUC order; therefore, the order is considered final.

Gas Meter Module Failures Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, N.D. area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function. In the May to July 2008 timeframe, NSP-Minnesota rebilled approximately 5,000 of these customers for their estimated consumption during the period the modules registered no consumption and then ceased rebilling as both the MPUC and North Dakota Public Service Commission (NDPSC) opened investigations into this matter.

Table of Contents

North Dakota Module Failures

On July 2, 2008, NSP-Minnesota received a letter from the NDPSC requesting further information on the AMR module failure. On Dec. 3, 2008, NSP-Minnesota made a filing with the NDPSC regarding its commitments and proposed remedies for rebilling affected customers. The filing outlined the proposed rebilling plan in detail, which committed to a 10-day, go-forward field response to customer inquiries regarding meter accuracy, offered an adjustment to the natural gas true-up to remove the commodity cost for the under recovered gas due to the rebilling process and indicated willingness to work with NDPSC staff on a service quality credit for customers experiencing a module failure.

On Feb. 27, 2009, NSP-Minnesota filed a request with the NDPSC to rebill the remaining North Dakota customers experiencing a module failure, reiterated the commitments made in previous filings and proposed a $50 service quality credit for each North Dakota customer experiencing a module failure. The proposed resolution package is expected to cost approximately $0.7 million. The NDPSC approved NSP-Minnesota s proposed resolution on April 13, 2009.

Minnesota Module Failures

On Aug. 1, 2008, the MPUC opened a docket and issued a notice directing NSP-Minnesota to file information about the AMR module failure. NSP-Minnesota responded to the MPUC on Aug. 21, 2008, proposing to rebill affected Minnesota customers for the unrecorded natural gas usage during the months that no consumption or intermittent usage was recorded. NSP-Minnesota proposed to employ the process provided by NSP-Minnesota s natural gas tariff and the MPUC s rules to estimate usage, which would be consistent with the process used whenever any other type of meter or module failure affecting the measurement of customer consumption occurs. The OAG and the OES subsequently submitted comments indicating support for the rebilling plan with certain conditions. The OAG raised concerns about the timing of the remediation efforts and questions whether customers should be responsible for the entire cost of the unbilled natural gas.

On Nov. 6, 2008, the MPUC reviewed the matter and directed NSP-Minnesota to provide additional information prior to making a final decision on the rebilling plan.

On Dec. 19, 2008, NSP-Minnesota met with MPUC staff, the OES and OAG and in January 2009 filed its response to the questions with the MPUC. NSP-Minnesota indicated a willingness to work with parties to develop a remedy for the current situation and to develop prospective service quality standards to address this and other concerns around billing accuracy. NSP-Minnesota has determined that a number of AMR modules designed for commercial customers are defective and as a result is broadening efforts to evaluate the performance of both gas and electric AMR modules.

On March 6, 2009, NSP-Minnesota filed an order with the MPUC to rebill the remaining Minnesota customers experiencing a module failure, reiterated the commitments made in previous filings and proposed a $50 service quality credit for each customer experiencing a module failure. The proposed resolution package is expected to cost approximately $0.9 million. Comments were filed on the proposed resolution on April 3, 2009, and reply comments were submitted on April 17, 2009. MPUC action is pending.

Annual Review of Remaining Lives On Feb. 17, 2009, NSP-Minnesota filed an order with the MPUC requesting an increase in proposed service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities and a depreciation study for other gas and electric assets, effective Jan 1, 2009. The OES recommended *provisional* approval to ensure that the decisions in this depreciation docket do not have unintended consequences in the pending NSP-Minnesota electric rate case. The OES recommended a 10-year lengthening of decommissioning life rather than the three-year level proposed by NSP-Minnesota, reducing the accrual for decommissioning by approximately $9 million. MPUC action is pending.

Pending and Recently Concluded Regulatory Proceedings   NDPSC and South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota South Dakota TCR and Environmental Cost Recovery (ECR) Rate Riders In December 2008, the SDPUC approved two rate riders for recovery of transmission investments and environmental costs effective Feb. 1, 2009. The TCR rider rate is set to recover approximately $1.9 million during 2009. The ECR Rider rate is set to recover approximately $2.5 million during 2009.

Both rate riders were allowed a ROE of 9.5 percent according to the terms of their respective settlement agreements. However, if NSP-Minnesota makes a general rate filing utilizing a 2008 test-year, the SDPUC may order that an appropriate ROE value be utilized under the rider mechanism, subject to true-up for the period from July 1, 2008 to the effective date of the order.

Table of Contents

Pending and Recently Concluded Regulatory Proceedings Federal Energy Regulatory Commission (FERC)

Revenue Sufficiency Guarantee (RSG) Charges In April 2006, the FERC issued an order determining that MISO had incorrectly applied its Transmission Energy Markets Tariff (TEMT) regarding the application of the RSG charge to certain transactions. The FERC ordered MISO to resettle all affected transactions retroactive to April 2005. The RSG charges are collected from MISO customers and paid to generators. In October 2006, the FERC issued an order granting rehearing in part and reversed the prior ruling requiring MISO to issue retroactive refunds, and ordered MISO to submit a compliance filing to implement prospective changes.

In March 2007, the FERC issued orders separately denying rehearing of the FERC order. Several parties filed appeals to the U.S. Court of Appeals for the District of Columbia seeking judicial review of the FERC s determinations of the allocation of RSG costs among MISO market participants. Xcel Energy intervened in each of these proceedings. In August 2007, Ameren Services Company and the Northern Indiana Public Service Company filed a joint complaint against MISO at the FERC, challenging the MISO s FERC-approved methodology for the recovery of RSG costs. In November 2007, the FERC issued an order instituting a proceeding to review evidence and to establish a RSG cost allocation methodology for market participants under the MISO TEMT. In March 2008, the MISO filed indicative tariff revisions that reflect an alternative mechanism for allocating RSG charges and costs. In August 2008, the FERC rejected this filing and issued an order commencing a hearing.

In November 2008, the FERC issued two orders related to RSG. One order requires the RSG charge allocation to include virtual supply transactions and requires resettlement of RSG charges retroactive to August 2007. The second order reversed a prior FERC decision and changed the RSG calculation methodology for the May 2006 to August 2007 retroactive period. Several parties filed requests for rehearing of the November 2008 FERC orders, arguing that the change in RSG allocation should be prospective. The recent RSG orders have caused several MISO market participant entities to default, which will affect the net financial impact of the orders of the electric production and transmission system of NSP-Minnesota, which is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System. On Feb. 23, 2009, MISO filed proposed compliance changes to the TEMT to redesign the RSG charges to better align cost recovery with cost causation. The RSG-related dockets are pending FERC action.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings Public Service Commission of Wisconsin (PSCW)

Other

2009 Electric Fuel Cost Recovery NSP-Wisconsin s fuel and purchased power costs for February 2009 were approximately $1.4 million, or 10.8 percent lower than authorized in the 2009 electric rate case limited reopener, which are outside the monthly and cumulative variance ranges for monitored fuel costs established by the PSCW. On April 16, 2009, the PSCW opened a proceeding to determine if a rate reduction, or fuel credit factor, should be ordered. The PSCW set NSP-Wisconsin s electric rates subject to refund with interest at 10.75 percent, pending a full review of 2009 fuel costs.

PSCo

Pending and Recently Concluded Regulatory Proceedings Colorado Public Utilities Commission (CPUC)

Base Rate

PSCo Electric Rate Case In November 2008, PSCo filed a request with the CPUC to increase Colorado electric rates by $174.7 million annually, or approximately 7.4 percent. The rate filing is based on a 2009 forecast test-year, an electric rate base of $4.2 billion, a requested ROE of 11.0 percent and an equity ratio of 58.08 percent. PSCo s request included a return of approximately $40 million for construction work in progress (CWIP) associated with incremental expenditures on the Comanche 3 unit since Jan. 1, 2007 pursuant to the 2004 Colorado least cost plan settlement agreement (a return on expenditures prior to Jan. 1, 2007 for Comanche 3 is included in existing rates). Under the settlement agreement, PSCo does not record allowance for funds used during construction (AFDC) income for the months this return is actually received from customers.

In February 2009, parties filed answer testimony in the case. The CPUC staff recommended an increase of $110 million based on a 10.37 percent ROE to be phased in with $70 million beginning in July and another $40 million in approximately January 2010. The Office of Consumer Counsel (OCC) recommended a $3.8 million increase based on a historic test-year

Table of Contents

and a 9.75 percent ROE. In March 2009, PSCo filed rebuttal testimony and revised its rate increase request to $159.3 million to reflect updated data. On April 10, 2009, intervenors filed surrebuttal testimony. The CPUC staff increased their revenue deficiency to $132.9 million based on an authorized ROE to 10.71 percent and an equity ratio of 58 percent. The CPUC staff also recommended a phase-in of rates with $70 million effective July 2009 and the remainder to be effective in January 2010. The OCC recommended an $11 million rate increase based on a historic year and an authorized ROE of 10 percent.

On April 22, 2009, a settlement agreement with CPUC staff, the OCC, Colorado Energy Consumers (an association of some of Public Service s larger commercial customers), CF&I Steel, LP d/b/a Rocky Mountain Steel Mills, Wal-Mart Stores, Inc., Sam s West, Inc., and Energy Outreach Colorado, was filed with the CPUC. The settlement provides for an overall $112.2 million increase in base rates, but does not provide for the specific resolution of many of the disputed issues such as ROE and capital structure. However, the settlement provides that incremental CWIP not included in existing rates for the Comanche Unit 3 be removed from rate base and that PSCo would be allowed to continue to record AFDC income on this balance until the Comanche Unit 3 is placed into service.

Hearings on the settlement began on April 24, 2009 and a final decision is expected in the summer of 2009. The settlement provides that parties support new rates to be effective on July 1, 2009.

Pending and Recently Concluded Regulatory Proceedings   FERC

Pacific Northwest FERC Refund Proceeding In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding administrative law judge (ALJ) concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC s orders in this proceeding with the U. S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Court of Appeals remanded the proceeding back to the FERC. The Court of Appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The FERC has yet to act on this order on remand.

SPS

Pending and Recently Concluded Regulatory Proceedings   Public Utility Commission of Texas (PUCT)

Base Rate

Texas Retail Base Rate Case On June 12, 2008, SPS filed a rate case with the PUCT seeking an annual rate increase of approximately $61.3 million, or approximately 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue would decline by $33.1 million, primarily due to fuel savings from the Lea Power Partners (LPP) purchase power agreement.

The rate filing is based on a 2007 test-year adjusted for known and measurable changes, a requested ROE of 11.25 percent, an electric rate base of $989.4 million and an equity ratio of 51.0 percent. Interim rates of $18 million for costs associated with the LPP power purchase agreement went into effect in September 2008.

In January 2009, SPS reached an agreement with intervenors, which provided for a base rate increase of $57.4 million. Key terms of the settlement include the following:

- An adjustment, which reduced depreciation expense by $5.6 million from currently authorized rates;
- Allows SPS to implement the transmission cost recovery factor in 2009;
- Precludes SPS from filing to seek any other change in base rates until Feb. 15, 2010; and
- Resolves all fuel reconciliation issues for 2006-07 with one adjustment for $0.6 million related to the sharing of certain wholesale sales revenues.

Table of Contents

The overall settlement is now pending final PUCT approval and the settlement rates are in effect subject to this final approval.

John Deere Wind Complaint In June 2007, several John Deere Wind Energy subsidiaries (JD Wind) filed a complaint against SPS disputing SPS payments to JD Wind for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind for energy produced from its qualifying facility (QF) are appropriate and in accordance with SPS filed tariffs with the PUCT. On March 25, 2009, the ALJ issued a proposal for decision, which recommends that SPS payment methodology to JD Wind is proper and that JD Wind s complaint be denied. The PUCT approved the proposal for decision during the April 23, 2009 open meeting.

Pending and Recently Concluded Regulatory Proceedings New Mexico Public Regulation Commission (NMPRC)

Base Rate

2008 New Mexico Retail Electric Rate Case On Dec. 18, 2008, SPS filed with the NMPRC a request to increase electric rates in New Mexico by approximately $24.6 million, or 6.2 percent. The request is based on a historic test-year (split year based on the year-ending June 30, 2008), an electric rate base of $321 million, and an equity ratio of 50 percent and a requested ROE of 12 percent. SPS also requested interim rates of $7.6 million per year to recover capacity costs of the Lea Power facility, which became operational in September 2008.

On March 26, 2009, the NMPRC approved a partial stipulated settlement between the parties that allows SPS to recover approximately $5.7 million of interim rates, effective May 1, 2009, through an LPP cost rider until the final rates from the remainder of the case are effective.

In April 2009, the parties reached an agreement in principle on key issues such as the amount of the rate increase and the earliest date that SPS can file its next base rate case, subject to a force majeure provision. The parties are working out the details to resolve other issues before a settlement agreement can be concluded, filed with the NMPRC and disclosed publicly. SPS expects to file the settlement documents with the NMPRC by the end of May 2009.

Pending and Recently Concluded Regulatory Proceedings FERC

Wholesale Rate Complaints In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer s Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustment charges to such customers (the Complaint). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to the complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS largest retail customer, intervened in the proceeding.

In May 2006, a FERC ALJ issued an initial decision in the proceeding. The ALJ found that SPS should recalculate its fuel and purchased economic energy cost adjustment clause (FCAC) billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by deducting from such costs the incremental fuel costs attributed to SPS sales of system firm capacity and associated energy to other wholesale customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales made out of temporarily excess capacity. In addition, the ALJ made recommendations on a number of base rate issues including a 9.64 percent ROE and the use of a 3-month coincident peak (CP) demand allocator.

Golden Spread Complaint Settlement In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. On April 21, 2008, the FERC approved the Settlement with a minor modification to the formula rate proposed by the FERC and accepted by the parties. The Settlement provides for:

- A $1.25 million payment by SPS to Golden Spread to resolve a dispute concerning the quantities Golden Spread was entitled to take under its existing partial requirements agreement for the years 2006 and 2007. The Settlement caps those quantities for the period 2008 through 2011. SPS is not required to make any fuel refunds to Golden Spread that were the subject of the Complaint under the terms of the Settlement.

Table of Contents

- An extended partial requirements contract at system average cost, with a capacity amount that ramps down over the period 2012 through 2019 from 500 MW to 200 MW. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals.

- Resolution of base rates in the Complaint without any adjustment to the existing rates for the period January 2005 through June 30, 2006. The Settlement also resolves all base rate issues in SPS subsequent proceeding related to the period July 1, 2006 through Sept. 30, 2008, other than the method to be used to allocate demand related costs and provided for two sets of agreed-on rates that are dependent on the ultimate resolution of that issue.

- For July 1, 2008 and beyond, Golden Spread will be under a formula rate for power supply service. The rate will be based on actual data from the most recent historic year adjusted for known and measurable changes and trued up to the actual performance in the subsequent calendar year.

Order on Wholesale Rate Complaints In April 2008, the FERC issued its Order on the Complaint applied to the remaining non-settling parties. The Order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006, for SPS full requirements customers who pay traditional cost-based rates and requires certain refunds.

- **Base Rates**: The FERC determined: (1) the ROE should be 9.33 percent; (2) rates should be based on a 12 CP allocator; and (3) the treatment of market based rate contracts in the test-year should be to credit revenues to the cost of service rather than allocating costs to the agreements. The revenue requirement established by the FERC results in proposed revenues that are estimated to be approximately $25 million, or approximately $6.9 million below the level charged to these customers during this 18-month period. Rates for full requirements customers, the New Mexico Cooperatives and Cap Rock, as well as an interruptible contract with PNM for the period beginning July 1, 2006, are the subject of settlements that have either been approved or are pending before the FERC.

- **Fuel Clause**: The FERC determined that the method for calculating fuel and purchased energy cost charges to the complaining customer is to deduct from such costs incremental fuel and purchased energy costs, which it is attributing to SPS market based intersystem sales on the basis that these are opportunity sales under its precedent. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005 (the refund effective date in the case). The FERC ordered SPS to file a compliance filing calculating its refund obligation and implement the instructions in the order in calculating its FCAC charges going forward from that date. While the order is subject to interpretation with respect to aspects of the calculation of the refund obligation, SPS does not expect its refund obligation to its full requirements customers from Jan. 1, 2005 through March 31, 2008, to exceed $11 million. PNM has filed a separate complaint that any refund obligation to PNM will be determined in that docket. SPS is reviewing the Order and has not yet determined whether to seek rehearing.

- The FERC also ruled on two other FCA issues. First, it required that wind contracts be evaluated on an individual contract basis rather than in aggregate. Second, the FERC determined that an after-the-fact screen should be applied to all QF purchases to determine if they are economic. While this review will require additional effort, it is not expected that this will result in additional refunds as all of the individual wind contracts as well as the QF purchases are typically economic when compared to market energy prices.

Several parties, including SPS, filed requests for rehearing on the order. These requests are pending before the FERC. In July 2008, SPS submitted its compliance report to the FERC. In the report, SPS has calculated the base rate refund for the 18-month period to be equal to $6.1 million and the fuel refund to be equal to $4.4 million. Several wholesale customers have protested the calculations. Once the final refund amounts are approved by the FERC, interest will be added to the refund due to the full requirements customers. As of March 31, 2009, SPS has accrued an amount sufficient to cover the estimated refund obligation.

SPS 2008 Wholesale Rate Case In March 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. Four New Mexico Cooperatives filed a motion for dismissal and protest in April 2008.

On May 30, 2008, the FERC conditionally accepted and suspended the rates and established hearing and settlement procedures. The FERC granted a one-day suspension of rates instead of 180 days. Lea Power achieved commercial operations in September 2008 and the proposed base rates of $9.9 million, based on a 10.25 percent ROE and a 12 CP demand allocator, became effective, subject to refund.

Table of Contents

The parties reached a settlement in principle, and an uncontested settlement was filed with the FERC on April 23, 2009. As a result of the settlement, SPS will receive an annual revenue increase of approximately $9.6 million or an overall percentage increase of 3.3 percent. SPS expects the FERC to approve the uncontested settlement.

7. Commitments and Contingent Liabilities

Except to the extent noted below, the circumstances set forth in Notes 16, 17 and 18 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2008, and Note 6 to the consolidated financial statements in this Quarterly Report on Form 10-Q appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include contingencies and unresolved contingencies that are material to Xcel Energy s financial position.

Guarantees

Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. As of March 31, 2009 and Dec. 31, 2008, Xcel Energy had issued guarantees of up to $66.5 million with $18.1 million and $17.9 million, respectively, of known exposure under these guarantees. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of March 31, 2009 and Dec. 31, 2008, was approximately $28.1 million and $27.9 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

Environmental Contingencies

Xcel Energy and its subsidiaries have been, or are currently involved with, the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties (PRPs) and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by Xcel Energy subsidiaries, predecessors, or other entities; and third-party sites, such as landfills, to which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At March 31, 2009, the liability for the cost of remediating these sites was estimated to be $71.3 million, of which $3.3 million was considered to be a current liability.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site NSP-Wisconsin has been named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior s Chequamegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2009 or 2010. In October 2004, the state of Wisconsin filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The state also alleges a claim for forfeitures and interest. This litigation was resolved in the first quarter of 2009, and all costs paid to the state are expected to be recoverable in rates.

Table of Contents

In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007. In June 2007, the EPA modified its remedial investigation report to establish final remedial action objectives (RAOs) and preliminary remediation goals (PRGs) for the Ashland site. In October 2007, the EPA approved the series of reports included in the remedial investigation report. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup.

In 2008, NSP-Wisconsin spent $0.8 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. On Dec. 4, 2008, the EPA approved the final feasibility study submitted by NSP-Wisconsin. The final feasibility study sets forth a range of remedial options under consideration by the EPA for the site but does not select a remedy. The EPA Remedy Review Board met in November 2008 to consider the remedial approach proposed by the Remedial Project Manager (RPM) for EPA Region 5. The remedy the EPA will suggest for the site, following input from the EPA Remedy Review Board, will be set forth in its proposed plan which is currently expected in 2009. The proposed plan will undergo public comment before the EPA makes its final remedy selection in its record of decision, which is currently expected to be issued in late 2009. The estimated remediation costs for the site range between $49.7 million and $137.5 million, including costs set forth in the feasibility study, as well as estimates for outside legal and consultant costs and work plan costs.

In addition to potential liability for remediation, NSP-Wisconsin may also have liability for natural resource damages (NRD) at the Ashland site. NSP-Wisconsin has indicated to the relevant natural resource trustees its interest in engaging in discussions concerning the assessment of natural resources injuries and in proposing various restoration projects in an effort to fully and finally resolve all NRD claims. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Until the EPA and the Wisconsin Department of Natural Resources (WDNR) select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility, NSP-Wisconsin s liability for the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. NSP-Wisconsin has recorded a liability of $65.9 million based on management s best estimate of remediation costs. NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for MGP-related environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

Third Party and Other Environmental Site Remediation

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation (ARO).

See additional discussion of AROs in Note 17 to the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2008. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA s Proposed Greenhouse Gas (GHG) Endangerment Finding On April 17, 2009, the EPA issued a proposed finding that GHGs threaten public health and welfare. This finding was in response to the U.S. Supreme Court s decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that GHGs are pollutants covered by the Clean Air Act and required the EPA to determine whether emissions of GHGs from motor vehicles endanger public health or welfare. The EPA s proposed endangerment finding applies to the Clean Air Act s mobile source program, and does not automatically

Table of Contents

trigger regulation under other provisions of the Clean Air Act that are applicable to stationary sources, such as power plants. As such, the proposed endangerment finding, in and of itself, does not impact Xcel Energy or its operating subsidiaries.

Clean Air Interstate Rule (CAIR) In March 2005, the EPA issued the CAIR to further regulate sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions. The objective of CAIR was to cap emissions of SO_2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy s service territory. In July 2008, the U. S. Court of Appeals for the District of Columbia vacated CAIR and remanded the rule to EPA. On Dec. 23, 2008, the court reinstated CAIR while the EPA develops new regulations in accordance with the court s July opinion.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

Under CAIR s cap-and-trade structure, SPS can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. The remaining capital investments for NOx controls in the SPS region are estimated at $ 4.5 million. For 2009, the estimated NOx allowance compliance costs are $1.9 million. Annual purchases of SO_2 allowances are estimated in the range of $1.7 million to $7.7 million each year, beginning in 2013, for phase I.

The EPA has drafted a proposed rule to stay the effectiveness of CAIR in Minnesota. As such, cost estimates are not included at this time for NSP-Minnesota. For 2009, the estimated NOx allowance costs for NSP Wisconsin are $1.7 million.

Allowance cost estimates for SPS and NSP-Wisconsin are based on March 2009 allowance costs and fuel quality. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

Clean Air Mercury Rule (CAMR) In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the U.S. Court of Appeals for the District of Columbia vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. Costs to comply with the Minnesota Mercury Emissions Reduction Act of 2006 are discussed in the following sections.

In Colorado, the Air Quality Control Commission (AQCC) passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and other specified units by 2014. The expected cost estimate for the Pawnee Generating Station is $2.3 million for capital costs with an annual estimate of $1.4 million for absorbent expense. PSCo is evaluating the emission controls required to meet the state rule for the remaining units and is currently unable to provide a total capital cost estimate.

Minnesota Mercury Legislation In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For NSP-Minnesota, the Act covers units at the A. S. King and Sherco generating facilities. Under the Act, Xcel Energy is operating and maintaining continuous mercury emission monitoring systems. The information obtained will be used to establish a baseline from which to measure mercury emission reductions.

Current plans are to install a sorbent injection system at both A. S. King and Sherco Unit 3. Implementation would occur by Dec. 31, 2009, at Sherco Unit 3 and by Dec. 31, 2010, for A. S. King. For these units, the current total capital cost estimate is $8.5 million, with the annual cost estimate of $4.3 million for A. S. King and $4.2 million for Sherco Unit 3. For Sherco Units 1 and 2, the current cost estimate is $13.6 million for capital and $10 million for annual expenses. On Nov. 6, 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans.

Utilities subject to the Act may also submit plans to address non-mercury pollutants subject to federal and state statutes and regulations, which became effective after Dec. 31, 2004. Cost recovery provisions of the Act also apply to these other environmental initiatives. In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs that are expected to be recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. On Aug. 26, 2008, NSP-Minnesota filed a request with the MPUC to increase the deferral to $19.4 million as NSP-Minnesota anticipated exceeding

Table of Contents

the authorized deferral amount in September 2008. On Nov. 21, 2008, NSP-Minnesota filed a request with the MPUC to reduce its deferred accounting request from $19.4 million to $8.7 million to reflect its requested recovery of nearly all emission reduction compliance costs incurred through 2009 in the NSP-Minnesota electric rate case, which was filed on Nov. 3, 2008.

Voluntary Capacity Upgrade and Emissions Reduction Filing In December 2007, NSP-Minnesota filed a plan with the Minnesota Pollution Control Agency (MPCA) and MPUC for reducing mercury emissions by up to 90 percent at the Sherco Unit 3 and A. S. King plants. Currently, the estimated project costs are approximately $8.5 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco Units 1 and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1 billion. The filing also contains alternatives for the MPUC to consider to add additional capacity and to achieve even lower emissions. If selected, these alternatives could range from $90.8 to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota s investments are subject to MPUC approval of a cost recovery mechanism. The MPCA has issued its assessment that the Sherco Unit 3 and A. S. King plans are appropriate. In light of recent significant changes in the national economy, lower forecast of energy consumption, and new information concerning an emerging technology that may be more cost effective, NSP-Minnesota filed a request with the MPUC to withdraw the plan on Nov. 6, 2008, to allow NSP-Minnesota to reevaluate alternatives. The MPUC granted the withdrawal request on Dec. 9, 2008.

Regional Haze Rules In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements.

States are required to identify the facilities that will have to reduce SO_2, NOx and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that the remaining cost for implementation of BART emission control projects is approximately $141 million in capital costs, which are included in the capital budget. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2011 and 2014. Colorado s state implementation plan has been submitted to the EPA for approval. In January 2009, the Colorado Air Pollution Control Division initiated a joint stakeholder process to evaluate what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado s Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The stakeholder process is expected to continue throughout 2009.

NSP-Minnesota submitted its BART alternatives analysis for Sherco Units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. On Nov. 13, 2008, NSP-Minnesota submitted a revised BART alternatives analysis letter to the MPCA to account for increased construction and equipment costs. The underlying conclusions and proposed emission control equipment, however, remain unchanged from the original 2006 BART analysis. The MPCA completed their BART determination and established SO_2 and NO_x limits that are equivalent to the reductions made under CAIR.

Federal Clean Water Act The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit (Court of Appeals) challenging the phase II rulemaking. In January 2007, the Court issued its decision and remanded the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state s best professional judgment until the EPA is able to fully respond to the Court of Appeals-ordered remand. In April 2008, the U.S. Supreme Court granted limited review of the Second Circuit s opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. On April 1, 2009, the U.S. Supreme Court issued a decision in *Entergy Corp. v. Riverkeeper, Inc.*, concluding that the EPA can, but is not required to, consider a cost benefit analysis when establishing BTA. The decision overturned only one aspect of the Court of Appeal s earlier opinion, and merely gives the EPA the discretion to consider costs and benefits when it reconsiders its phase II rules. Until the EPA fully responds to the Court of Appeal s decision, the rule s compliance requirements and associated deadlines will remain unknown. As such, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

Table of Contents

The MPCA exercised its authority under best professional judgment to require the Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake s impact on aquatic wildlife. NSP-Minnesota is discussing alternatives with the local community and regulatory agencies to address this concern.

PSCo Notice of Violation (NOV) In July 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche Station and Pawnee Station in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy s financial position and results of operations.

Gas Trading Litigation

e prime is a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Twelve lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin, in one instance), alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP-Wisconsin deny these allegations and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas-trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the United States District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned *Texas-Ohio Energy vs. CenterPoint Energy et al.* The other eleven cases arising out of the same or similar set of facts are captioned *Fairhaven Power Company vs. EnCana Corporation et al.; Ableman Art Glass vs. EnCana Corporation et al.; Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. et al.; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al.; Learjet, Inc. vs. e prime and Xcel Energy Inc et al.; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al.; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al.; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. et al.; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al. and Hartford Regional Medical Center vs. e prime, Xcel Energy et al*. Many of these cases involve multiple defendants and have been transferred to Judge Phillip Pro of the United States District Court in Nevada, who is the judge assigned to the Western Area Wholesale Natural Gas Antitrust Litigation.

In April 2005, Judge Pro granted defendants motion to dismiss in *Texas-Ohio Energy* based upon the filed rate doctrine. Based upon this same legal doctrine, Judge Pro subsequently granted defendants motion to dismiss in *Fairhaven Power Company, Ableman Art Glass and Utility Savings and Refund Services*. Plaintiffs subsequently appealed these dismissals to the U.S. Court of Appeals for the Ninth Circuit. In September 2007, the Court of Appeals reversed the dismissal and remanded the lawsuits to Judge Pro for consideration of whether any of plaintiffs claims are based upon retail rates not directly barred by the filed rate doctrine. e prime and some other defendants were dismissed from the *Breckenridge Brewery* lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

All of the gas trading lawsuits are in the early procedural stages of litigation. No trial dates have been set for any of these lawsuits; however, defendants summary judgment motions are pending in the *Learjet* and *J.P. Morgan* matters. In January 2009, the parties reached a settlement agreement in principle in the *Abelman Art Glass, Ever Bloom, Fairhaven Power Company, Texas-Ohio Energy*, and *Utility Savings and Refund Services* cases. The terms of the settlement in principle will not have a material financial effect upon Xcel Energy. Per court order, discovery in most of the remaining cases must be completed by Sept. 5, 2009. Trial for all cases venued in Nevada will likely be set for late 2009 or early 2010.

In November 2007, the *Missouri Public Service Commission* case was remanded to Missouri state court. On Jan. 13, 2009, the Missouri state court granted defendants motion to dismiss plaintiff s complaint for lack of standing. Plaintiffs have filed an appeal.

Table of Contents

In late March 2009, *Newpage Wisconsin System Inc.* commenced a lawsuit in state court in Wood County, Wis. The allegations are substantially similar to *Arandell* and name several defendants, including Xcel Energy, e prime and NSP-Wisconsin. As with *Arandell*, Xcel Energy, e prime and NSP-Wisconsin believe the allegations asserted against them are without merit and they intend to vigorously defend against the asserted claims.

Environmental Litigation

Carbon Dioxide (CO_2) Emissions Lawsuit In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. In October 2004, Xcel Energy and the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the court granted the motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit. In June 2007, the Court of Appeals issued an order requesting the parties to file a letter brief regarding the impact of the United States Supreme Court s decision in *Massachusetts v. EPA*, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in *Massachusetts v. EPA*, the United States Supreme Court held that CO_2 emissions are a pollutant subject to regulation by the EPA under the CAA. In July 2007, in response to the request of the Court of Appeals, the defendant utilities filed a letter brief stating the position that the United States Supreme Court s decision supports the arguments raised by the utilities on appeal. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants CO_2 emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. In September 2007, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Fifth Circuit. Oral arguments were presented to the Court of Appeals on Aug. 6, 2008. Pursuant to the court s order of Sept. 26, 2008, re-argument was held on Nov. 3, 2008. No explanation was given for the order. The Court of Appeals has taken the matter under advisement.

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utilities, oil, gas and coal companies. The suit was brought on behalf of approximately 400 native Alaskans, the Inupiat Eskimo, who claim that defendants emission of CO_2 and other GHG contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence, the entire village must be relocated at a cost of between $95 million and $400 million. Plaintiffs assert a nuisance claim under federal and state common law, as well as a claim asserting concert of action in which defendants are alleged to have engaged in tortious acts in concert with each other. Xcel Energy was not named in the civil conspiracy claim. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008. The matter has now been fully briefed, with oral arguments set for May 19, 2009. It is unknown when the court will render a decision.

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy In June 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota s distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. After its motion to dismiss plaintiffs claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007, the court granted NSP-Minnesota s motion for certification, and oral arguments took place on Sept. 11, 2008. Mediation took place on Oct. 14, 2008, but the matter was not resolved. In December 2008, the Court of Appeals issued a decision ordering dismissal of Plaintiffs claims for injunctive relief, but otherwise rejecting NSP-Minnesota s contentions and ordering the matter remanded for trial. The Minnesota Supreme Court subsequently granted NSP-Minnesota s petition for further review on Feb. 17, 2009.

Table of Contents

Qwest vs. Xcel Energy Inc. In June 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Colorado state court in Denver. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. Pursuant to this agreement, Qwest asserted PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. In May 2006, PSCo filed a counterclaim against Qwest asserting Qwest had a duty to PSCo and an obligation under the contract to maintain its poles in a safe and serviceable condition. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. On June 16, 2008, Qwest filed its appellate brief. The matter has been fully briefed by the parties and oral arguments were presented on Feb. 18, 2009. PSCo is currently awaiting a decision by the court.

Hoffman vs. Northern States Power Company In March 2006, a purported class action complaint was filed in Minnesota state court, on behalf of NSP-Minnesota s residential customers in Minnesota, North Dakota and South Dakota for alleged breach of a contractual obligation to maintain and inspect the points of connection between NSP-Minnesota s wires and customers homes within the meter box. Plaintiffs claim NSP-Minnesota s alleged breach results in an increased risk of fire and is in violation of tariffs on file with the MPUC. Plaintiffs seek injunctive relief and damages in an amount equal to the value of inspections plaintiffs claim NSP-Minnesota was required to perform over the past six years. In August 2006, NSP-Minnesota filed a motion for dismissal on the pleadings. In November 2006, the court issued an order denying NSP-Minnesota s motion, but later, pursuant to a motion by NSP-Minnesota, certified the issues raised in NSP-Minnesota s original motion for appeal as important and doubtful, and NSP-Minnesota filed an appeal with the Minnesota Court of Appeals. In January 2008, the Minnesota Court of Appeals determined the plaintiffs claims are barred by the filed rate doctrine and remanded the case to the district court for dismissal. Plaintiffs petitioned the Minnesota Supreme Court for discretionary review, and the Supreme Court granted the petition. On April 16, 2009, the Minnesota Supreme Court determined that the filed rate doctrine barred plaintiffs claims for compensatory damages and that under the primary jurisdiction doctrine plaintiffs claims for injunctive relief should be heard by the MPUC. The Supreme Court stated that claims relating to North Dakota and South Dakota residents were not properly before the Court and should therefore be remanded to the district court for disposition consistent with the Supreme Court s decision.

MGP Insurance Coverage Litigation In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and LaCrosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin s insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions. NSP-Wisconsin has also reached settlements in principle with Ranger Insurance Company (Ranger), TIG Insurance Company (TIG), Royal Indemnity Company and Globe Indemnity Company.

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of 11 insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Minnesota Court of Appeals challenging the dismissal of these carriers. In November 2007, Ranger and TIG filed a motion to dismiss NSP-Wisconsin s appeal, asserting that NSP-Wisconsin s failure to serve Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company (Harbor), requires dismissal of NSP-Wisconsin s appeal. In February 2008, the Court of Appeals issued an order deferring a decision on the procedural motion filed by Harbor and TIG and referring the motion to the panel assigned to consider the merits of the appeal.

In April 2008, the Court of Appeals issued an order staying briefing and other appellate proceedings until further order of the court. The order was issued in response to NSP-Wisconsin s request that oral argument be deferred pending a decision by the Wisconsin Supreme Court in *Plastics Engineering Co. vs. Liberty Mutual Insurance Co*. On Jan. 29, 2009, the Wisconsin Supreme Court issued its decision in Plastics Engineering Co., adopting an all sums method of allocating damages when an injury spans multiple, successive policy periods. On Feb. 3, 2009, the Court of Appeals issued an order dissolving the stay and establishing a briefing schedule. NSP-Wisconsin filed its supplemental brief addressing the impact of *Plastics Engineering Co*. on March 9, 2009. The insurers filed their initial briefs on April 9, 2009, and NSP-Wisconsin has until May 4, 2009 to reply to the insurers briefs.

Table of Contents

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy s consolidated financial statements.

Nuclear Waste Disposal Litigation In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy s (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE s motion for reconsideration. In February 2008, the DOE filed an appeal to the U.S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. In April 2008, the DOE asked the Court of Appeals to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court of Appeals granted the request. In December 2008, NSP-Minnesota made a motion in the Court of Appeals to lift the stay, which was denied by the Court of Appeals in February 2009. Results of the judgment will not be recorded in earnings until the appeal, regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the U.S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE s continuing failure to abide by the terms of the contract. This lawsuit will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. Per the court s scheduling order, NSP-Minnesota s expert report on damages was submitted on April 15, 2009, and asserts damages in excess of $250 million. The DOE must file its expert report by Oct. 15, 2009, and all discovery must be completed by the end of 2009. Trial is expected to take place in 2010.

Fargo Gas Explosion In September 2008, an explosion occurred at a duplex in Fargo, N.D. The explosion destroyed one side of the duplex and resulted in injuries to some of the residents. Xcel Energy subsequently provided a report to the U.S. Dept. of Transportation Pipeline and Hazardous Materials Safety Administration stating that natural gas migrated into the house and was ignited by an unknown source. Investigators identified a natural gas leak the size of a pinhole located 18 inches underground. The property owners and attorneys representing the injured residents have put Xcel Energy on notice of potential claims. Investigation into the incident is continuing.

Mallon vs. Xcel Energy Inc. In August 2007, Xcel Energy, PSCo and PSR Investments, Inc. (PSRI) commenced a lawsuit in Colorado state court against Theodore Mallon and TransFinancial Corporation seeking damages for, among other things, breach of contract and breach of fiduciary duties associated with the sale of Corporate Owned Life Insurance (COLI) policies. In May 2008, Xcel Energy, PSCo and PSRI filed an amended complaint that, among other things, adds Provident Life & Accident Insurance Company (Provident) as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. On June 23, 2008, Provident filed a motion to dismiss the complaint. On Oct. 22, 2008, the court granted Provident s motion in part, but denied the motion with respect to a majority of the core causes of action asserted by PSCo, Xcel Energy and PSRI. In January 2009, the court granted defendant Mallon s motion to amend his answer to, among other things, add a counterclaim for breach of contract and fraud against plaintiffs PSRI, PSCo and Xcel Energy. Xcel Energy believes the counterclaims are without merit and filed a motion to dismiss. The court took this motion under advisement. It is uncertain when a decision will be issued.

Cabin Creek Hydro Generating Station Accident In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo s Cabin Creek Hydro Generating Station near Georgetown, Colo. This work was being performed as part of a corrosion prevention effort. A fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U.S. Chemical Safety Board and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008, the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17,

Table of Contents

2008. The Court ordered this proceeding stayed until March 3, 2009 and subsequently extended the stay to October 2009. A lawsuit has been filed in Colorado state court in Denver on behalf of four of the deceased workers and four of the injured workers (Foster, et. al. v. PSCo, et. al.). PSCo and Xcel Energy are named as defendants in that case, along with RPI Coatings and related companies and the two other contractors who also performed work in connection with the relining project at Cabin Creek. A second lawsuit (Ledbetter et. al vs. PSCo et. al) has also been filed in Colorado state court in Denver on behalf of three employees allegedly injured in the accident. A third lawsuit was filed on behalf of one of the deceased RPI workers in the California state court (Aguirre v. RPI, et. al.), naming PSCo, RPI, and the two other contractors as defendants. The court subsequently dismissed the Aguirre lawsuit, and it is anticipated that the plaintiff will refile the lawsuit in Colorado. Xcel Energy and PSCo intend to vigorously defend themselves against the claims asserted in all three lawsuits.

Fru-Con Construction Corporation vs. Utility Engineering Corporation (UE) et al. In March 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con s complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE s motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

Lamb County Electric Cooperative (LCEC) In 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging SPS was unlawfully providing service to oil field customers in LCEC s certificated area. In May 2003, the PUCT issued an order denying LCEC s petition based on its determination that SPS in 1976 was granted a certificate to serve the disputed customers. LCEC appealed the decision to the Texas state court. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the decision to the Court of Appeals for the Third Supreme Judicial District. In November 2008, the Court of Appeals issued an opinion affirming the decision in favor of SPS. In December 2008, LCEC filed a petition for review with the Supreme Court of Texas. On Feb. 27, 2009, the Supreme Court of Texas denied LCEC s request for review.

In 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination of the legality of SPS providing electric service to the disputed customers. The PUCT order from May 2003, which found SPS was legally serving the disputed customers, collaterally determines the issue of liability contrary to LCEC s position in the suit. Because the PUCT May 2003 order has been affirmed, SPS will move for summary judgment if LCEC does not dismiss this case.

8. Short-Term Borrowings and Other Financing Instruments

Commercial Paper At March 31, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $313.0 million and $330.3 million, respectively. The weighted average interest rates at March 31, 2009 and Dec. 31, 2008 were 1.30 percent and 3.53 percent, respectively. At March 31, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had combined board approval to issue up to $2.25 billion of commercial paper.

Credit Facility Bank Borrowings At March 31, 2009 and Dec. 31, 2008, Xcel Energy and its subsidiaries had credit facility bank borrowings of $125.0 million. The weighted average interest rates at March 31, 2009 and Dec. 31, 2008, were 1.33 percent and 1.88 percent, respectively.

Money Pool Xcel Energy and its utility subsidiaries have established a money pool arrangement that allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates. The money pool arrangement does not allow loans from the subsidiaries to the holding company. At March 31, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had money pool loans outstanding of $19.0 million and $104.5 million, respectively. The money pool loans are eliminated upon consolidation. The weighted average interest rates at March 31, 2009 and Dec. 31, 2008, were 1.20 percent and 3.48 percent, respectively.

Table of Contents

9. Long-Term Borrowings and Other Financing Instruments

On March 1, 2009, NSP-Wisconsin redeemed its 7.375 percent $65.0 million first mortgage bonds due Dec. 1, 2026. In addition to repayment of all principal amounts, NSP-Wisconsin paid accrued interest and a redemption premium totaling approximately $3.0 million.

10. Derivative Instruments

Effective Jan. 1, 2009, Xcel Energy adopted SFAS No. 161, which requires additional disclosures regarding why an entity uses derivative instruments, the volume of an entity s derivative activities, the fair value amounts recorded to the consolidated balance sheet for derivatives, the gains and losses on derivative instruments included in the consolidated statement of income or deferred, and information regarding certain credit-risk-related contingent features in derivative contracts.

Xcel Energy and its utility subsidiaries enter into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices. See additional information pertaining to the valuation of derivative instruments in Note 11 to the consolidated financial statements.

Interest Rate Derivatives Xcel Energy and its utility subsidiaries 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 a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

At March 31, 2009, accumulated other comprehensive income related to interest rate derivatives included $0.7 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest transactions impact earnings.

At March 31, 2009, Xcel Energy had one unsettled interest rate swap outstanding at SPS with a notional amount of $25 million. The interest rate swap is not designated as a hedging instrument, and as such, changes in fair value for the interest rate swap are recorded to earnings.

Commodity Derivatives Xcel Energy s utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices in their electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At March 31, 2009, Xcel Energy had various utility commodity and vehicle fuel related contracts designated as cash flow hedges extending through December 2010. Changes in the fair value of cash flow hedges 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 the regulatory recovery mechanisms in place. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three months ended March 31, 2009 and 2008.

At March 31, 2009, Xcel Energy had $9.9 million of net losses in accumulated other comprehensive income related to utility commodity and vehicle fuel cash flow hedges; $6.2 million is expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Xcel Energy s utility subsidiaries also enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of these derivative instruments are deferred as a regulatory asset or liability, based on the regulatory recovery mechanisms in place.

Additionally, Xcel Energy s utility subsidiaries enter into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving their electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in income. See additional discussion regarding Xcel Energy s use of trading commodity derivatives in Derivatives, Risk Management and Market Risk in Item 2 Management s Discussion and Analysis.

Xcel Energy had no derivative instruments designated as fair value hedges during the three months ended March 31, 2009,

Table of Contents

and as such, had no gains or losses from fair value hedges or related hedged transactions for the period.

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

	March 31, 2009		Dec. 31, 2008	
(Thousands of Dollars)	Derivative Instruments Valuation - Assets	Derivative Instruments Valuation - Liabilities	Derivative Instruments Valuation - Assets	Derivative Instruments Valuation - Liabilities
Long-term purchased power agreements	$ 361,674	$ 346,241	$ 374,692	$ 353,531
Commodity derivatives	31,691	46,994	52,968	54,307
Interest rate derivatives		7,747		8,503
Total	$ 393,365	$ 400,982	$ 427,660	$ 416,341

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, Xcel Energy 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, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Financial Impact of Qualifying Cash Flow Hedges The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy s accumulated other comprehensive income, included in the consolidated statements of common stockholders equity and comprehensive income, is detailed in the following table:

	Three Months Ended March 31,	
(Thousands of Dollars)	2009	2008
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (13,113)	$ (1,416)
After-tax net unrealized losses related to derivatives accounted for as hedges	(110)	(5,601)
After-tax net realized losses (gains) on derivative transactions reclassified into earnings	1,310	(25)
Accumulated other comprehensive loss related to cash flow hedges at March 31	$ (11,913)	$ (7,042)

The following table details the fair value of derivatives recorded to derivative instruments valuation in the consolidated balance sheet, by category:

	March 31, 2009		
(Thousands of Dollars)	Fair Value	Counterparty Netting (a)	Derivative Instruments Valuation
Current derivative assets			
Derivatives designated as cash flow hedges			
Electric commodity	$ 3,758	$ 311	$ 4,069

Natural gas commodity		323		(6)		317
		4,081		305		4,386
Other derivative instruments:						
Trading commodity		17,914		(6,726)		11,188
Electric commodity		253				253
		18,167		(6,726)		11,441
Total current derivative assets	$	22,248	$	(6,421)	$	15,827
Noncurrent derivative assets						
Other derivative instruments:						
Trading commodity	$	19,704	$	(3,918)	$	15,786
Natural gas commodity		78				78
Total noncurrent derivative assets	$	19,782	$	(3,918)	$	15,864
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Electric commodity	$	3,472	$	311	$	3,783
Natural gas commodity		1,974		(672)		1,302
Vehicle fuel and other commodity		6,650				6,650
		12,096		(361)		11,735
Other derivative instruments:						
Interest rate		1,514				1,514
Trading commodity		15,631		(11,906)		3,725
Electric commodity		1,670				1,670
Natural gas commodity		18,516		(9,730)		8,786
		37,331		(21,636)		15,695
Total current derivative liabilities	$	49,427	$	(21,997)	$	27,430
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$	3,875	$		$	3,875
Other derivative instruments:						
Interest rate		6,233				6,233
Trading commodity		15,695		(3,919)		11,776
Natural gas commodity		5,427				5,427
		27,355		(3,919)		23,436
Total noncurrent derivative liabilities	$	31,230	$	(3,919)	$	27,311

Table of Contents

(a) FASB Interpretation No. 39 *Offsetting of Amounts Relating to Certain Contracts*, as amended by FASB Staff Position FIN 39-1 *Amendment of FASB Interpretation No. 39*, permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table details the impact of derivative activity during the three months ended March 31, 2009, on other comprehensive income, regulatory assets and liabilities, and income:

	Fair Value Changes Recognized During the Period in:		**Pre-Tax Amounts Reclassified into Income During the Period from:**		**Pre-Tax Gains (Losses) Recognized During the Period in Income**
(Thousands of Dollars)	**Other Comprehensive Income (Loss)**	**Regulatory Assets and Liabilities**	**Other Comprehensive Income (Loss)**	**Regulatory Assets and Liabilities**	
Derivatives designated as cash flow hedges:					
Interest rate	$	$	$ 299(a)	$	$
Electric commodity		(19,556)		(3,512)(c)	
Natural gas commodity		(16,870)		77,877(d)	(30,241)(d)
Vehicle fuel and other commodity	(187)		1,889(e)		
	$ (187)	$ (36,426)	$ 2,188	$ 74,365	$ (30,241)
Other derivative instruments:					
Interest rate	$	$	$	$	$ 756(a)
Trading commodity					3,393(b)
Electric commodity		(1,738)		321(c)	
Natural gas commodity		(14,646)		15(d)	
	$	$ (16,384)	$	$ 336	$ 4,149

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues.

(c) Recorded to electric fuel and purchased power; these derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

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

(e) Recorded to other operating and maintenance expenses.

28

Table of Contents

At March 31, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 20,998,000 megawatt hours (MwH) of electricity, 22,466,000 MMBtu of natural gas, and 5,565,000 gallons of vehicle fuel. These amounts reflect the gross notional amounts of futures, forwards and financial transmission rights and are not reflective of net positions in the underlying commodities. Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

Credit Related Contingent Features Contract provisions of the utility subsidiaries derivative instruments may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit rating. If the credit rating of PSCo at March 31, 2009, were downgraded below investment grade, contracts underlying $2.6 million of derivative instruments in a liability position would have required Xcel Energy to post collateral or settle the contracts, which would have resulted in payments to applicable counterparties of $2.6 million. At March 31, 2009, there was no collateral posted on these specific contracts.

Certain of the utility subsidiaries derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary s ability to fulfill its contractual obligations is reasonably expected to be impaired. As of March 31, 2009, Xcel Energy s utility subsidiaries had no collateral posted related to adequate assurance clauses in derivative contracts.

11. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted *Fair Value Measurements* (SFAS No. 157) for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights (FTRs).

The following tables present, for each of these hierarchy levels, Xcel Energy s assets and liabilities that are measured at fair value on a recurring basis:

	March 31, 2009				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Counterparty Netting	Net Balance
Assets					
Cash equivalents	$	$ 60,000	$	$	$ 60,000
Nuclear decommissioning fund	412,453	503,999	105,552		1,022,004
Commodity derivatives		19,156	22,874	(10,339)	31,691
Total	$ 412,453	$ 583,155	$ 128,426	$ (10,339)	$ 1,113,695
Liabilities					
Commodity derivatives	$	$ 53,727	$ 19,183	$ (25,916)	$ 46,994
Interest rate derivatives		7,747			7,747
Total	$	$ 61,474	$ 19,183	$ (25,916)	$ 54,741

29

Table of Contents

	Dec. 31, 2008				
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Counterparty Netting**	**Net Balance**
Assets					
Cash equivalents	$	$ 50,000	$	$	$ 50,000
Nuclear decommissioning fund	465,936	499,935	109,423		1,075,294
Commodity derivatives		29,648	39,565	(16,245)	52,968
Total	$ 465,936	$ 579,583	$ 148,988	$ (16,245)	$ 1,178,262