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REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of Xcel Energy's financial statements. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include some amounts that are based on management's estimates and judgment.

To fulfill its responsibility, management maintains a strong internal control structure, supported by formal policies and procedures that are communicated throughout Xcel Energy. Management also maintains a staff of internal auditors who evaluate the adequacy of and investigate the adherence to these controls, policies and procedures.

Our independent public accountants have audited the financial statements and have rendered an opinion as to the statements' fairness of presentation, in all material respects, in conformity with generally accepted accounting principles in the United States. During the audit, they obtained an understanding of Xcel Energy's internal control structure, and performed tests and other procedures to the extent required by generally accepted auditing standards in the United States.

The board of directors pursues its oversight role with respect to Xcel Energy's financial statements through the Audit Committee, which is comprised solely of nonmanagement directors. The committee meets periodically with the independent public accountants, internal auditors and management to ensure that all are properly discharging their responsibilities. The committee approves the scope of the annual audit and reviews the recommendations the independent public accountants have for improving the internal control structure. The board of directors, on the recommendation of the Audit Committee, engages the independent public accountants.

Both the independent public accountants and the internal auditors have unrestricted access to the Audit Committee.

Wayne H. Brunetti
President and Chief Executive Officer

Edward J. McIntyre
Vice President and Chief Financial Officer

Xcel Energy Inc.
Minneapolis, Minnesota
March 2, 2001

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries as of Dec. 31, 2000 and 1999, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended Dec. 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the consolidated financial statements of NRG Energy, Inc. for the year ended Dec. 31, 2000, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets and revenues of 28 percent and 17 percent, respectively, of the related consolidated totals. We also did not audit the consolidated financial statements of Northern States Power Co., for the years ended Dec. 31, 1999 or 1998, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets of 54 percent in 1999 and total revenues of 44 percent and 46 percent in 1999 and 1998, respectively, of the related consolidated totals. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. and Northern States Power Co. for the periods described above, is based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and its subsidiaries as of Dec. 31, 2000 and 1999, and the results of their operations and their cash flows for each of the years in the three-year period ended Dec. 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Arthur Andersen LLP
Minneapolis, Minnesota
March 2, 2001

REPORTS OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the consolidated balance sheet and the related consolidated statements of income, of stockholders' equity and cash flows present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (not presented separately herein) at Dec. 31, 2000, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 2, 2001

To the Shareholders of Xcel Energy Inc.:

In our opinion, the consolidated balance sheets and statements of capitalization as of Dec. 31, 1999, and the related consolidated statements of income, of common stockholders' equity and of cash flows for the years ended Dec. 31, 1999 and 1998, of Northern States Power Co. and its subsidiaries (not presented separately herein) present fairly, in all material respects, the results of operations and cash flows of Northern States Power Co. and its subsidiaries for the years ended Dec. 31, 1999 and 1998, and its financial position at Dec. 31, 1998, in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
Jan. 31, 2000, except as to Note 2,
which is as of Feb. 22, 2000

(Thousands of dollars, except per share data)	2000	1999	1998
	Year ended December 31		
OPERATING REVENUES:			
Electric utility	$ 5,679,925	$4,921,612	$4,984,232
Gas utility	1,468,880	1,141,429	1,110,004
Electric and gas trading	2,056,399	951,490	135,471
Nonregulated and other	2,203,878	688,888	382,603
Equity earnings from investments in affiliates	182,714	112,124	115,985
Total revenue	11,591,796	7,815,543	6,728,295
OPERATING EXPENSES:			
Electric fuel and purchased power – utility	2,568,150	1,958,912	1,973,043
Cost of gas sold and transported – utility	948,145	683,455	659,493
Electric and gas trading costs	2,016,927	946,139	133,508
Cost of sales – nonregulated and other	1,047,617	323,262	203,958
Other operating and maintenance expenses – utility	1,398,708	1,327,797	1,354,980
Other operating and maintenance expenses – nonregulated	656,260	302,201	223,374
Depreciation and amortization	792,395	679,851	627,438
Taxes (other than income taxes)	351,412	360,916	356,045
Special charges (see Note 2)	241,042	31,114	790
Total operating expenses	10,020,656	6,613,647	5,532,629
Operating income	1,571,140	1,201,896	1,195,666
OTHER INCOME (EXPENSE):			
Minority interest	(40,489)	(2,773)	
Gain on sale of nonregulated projects			29,951
Interest income and other – net	16,107	4,560	22,390
Total other income (expense)	(24,382)	1,787	52,341
INTEREST CHARGES AND FINANCING COSTS:			
Interest charges – net of amounts capitalized	657,305	414,277	344,643
Distributions on redeemable preferred securities of subsidiary trusts	38,800	38,800	33,311
Dividend requirements and redemption premium on preferred stock of subsidiaries			5,332
Total interest and financing costs	696,105	453,077	383,286
Income before income taxes and extraordinary items	850,653	750,606	864,721
Income taxes	304,865	179,673	240,391
Income before extraordinary items	545,788	570,933	624,330
Extraordinary items, net of income taxes of $8,549 (see Note 12)	(18,960)		
Net income	526,828	570,933	624,330
Dividend requirements and redemption premiums on preferred stock	4,241	5,292	5,548
Earnings available for common shareholders	$ 522,587	$ 565,641	$ 618,782
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	337,832	331,943	323,883
Diluted	338,111	332,054	324,355
EARNINGS PER SHARE – BASIC AND DILUTED:			
Income before extraordinary items	$ 1.60	$ 1.70	$ 1.91
Extraordinary items (see Note 12)	(0.06)		
Earnings per share	$ 1.54	$ 1.70	$ 1.91

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Year ended December 31 2000	1999	1998
OPERATING ACTIVITIES:			
Net income	$ 526,828	$ 570,933	$ 624,330
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	828,780	718,323	659,226
Nuclear fuel amortization	44,591	50,056	43,816
Deferred income taxes	62,716	18,161	5,231
Amortization of investment tax credits	(15,295)	(14,800)	(14,654)
Allowance for equity funds used during construction	3,848	(1,130)	(8,509)
Undistributed equity in earnings of unconsolidated affiliates	(87,019)	(67,926)	(56,952)
Write-down of investments in projects			26,740
Gain on sale of nonregulated projects		(37,194)	(26,200)
Special charges – noncash	96,113	31,114	
Conservation incentive adjustments – noncash	19,248	71,348	
Extraordinary items (see Note 12)	18,960		
Change in accounts receivable	(443,347)	(113,521)	8,373
Change in inventories	21,933	(44,183)	(12,550)
Change in other current assets	(484,288)	(164,995)	22,263
Change in accounts payable	713,069	214,791	2,105
Change in other current liabilities	129,557	81,056	60,618
Change in other assets and liabilities	(27,969)	13,396	27,767
Net cash provided by operating activities	1,407,725	1,325,429	1,361,604
INVESTING ACTIVITIES:			
Nonregulated capital expenditures and asset acquisitions	(2,196,168)	(1,620,462)	(58,748)
Utility capital/construction expenditures	(984,935)	(1,178,663)	(1,014,710)
Allowance for equity funds used during construction	(3,848)	1,130	8,509
Investments in external decommissioning fund	(48,967)	(39,183)	(41,360)
Equity investments, loans and deposits for nonregulated projects	(93,366)	(240,282)	(234,214)
Collection of loans made to nonregulated projects	17,039	81,440	109,530
Other investments – net	(36,749)	43,136	10,011
Net cash used in investing activities	(3,346,994)	(2,952,884)	(1,220,982)
FINANCING ACTIVITIES:			
Short-term borrowings – net	42,386	1,315,027	(84,471)
Proceeds from issuance of long-term debt	3,565,227	1,215,312	641,123
Repayment of long-term debt, including reacquisition premiums	(1,667,315)	(465,045)	(394,506)
Proceeds from issuance of preferred securities			187,700
Proceeds from issuance of common stock	116,678	95,317	234,171
Proceeds from the public offering of NRG stock	453,705		
Redemption of preferred stock, including reacquisition premiums	(20)		(276,824)
Dividends paid	(494,992)	(492,456)	(476,172)
Net cash provided by (used in) financing activities	2,015,669	1,668,155	(168,979)
Effect of exchange rate changes on cash	360		
Net increase (decrease) in cash and cash equivalents	76,760	40,700	(28,357)
Cash and cash equivalents at beginning of year	139,731	99,031	127,388
Cash and cash equivalents at end of year	$ 216,491	$ 139,731	$ 99,031
Supplemental disclosure of cash flow information			
Cash paid for interest (net of amount capitalized)	$ 610,584	$ 458,897	$ 397,680
Cash paid for income taxes (net of refunds received)	$ 216,087	$ 193,448	$ 209,781

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*December 31* 2000	1999
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 216,491	$ 139,731
Accounts receivable – net of allowance for bad debts: $41,350 and $13,043, respectively	1,289,724	800,066
Accrued unbilled revenues	683,266	410,798
Materials and supplies inventories	286,453	306,524
Fuel and gas inventories	194,380	152,874
Recoverable purchased gas and electric energy costs	283,167	54,916
Prepayments and other	174,593	196,035
Total current assets	3,128,074	2,060,944
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Electric utility plant	15,304,407	14,807,684
Gas utility plant	2,376,868	2,266,516
Nonregulated property and other	5,641,968	3,242,410
Construction work in progress	622,494	533,046
Total property, plant and equipment	23,945,737	20,849,656
Less: accumulated depreciation	(8,759,322)	(8,153,434)
Nuclear fuel – net of accumulated amortization: $967,927 and $923,336, respectively	86,499	102,727
Net property, plant and equipment	15,272,914	12,798,949
OTHER ASSETS:		
Investments in unconsolidated affiliates	1,459,410	1,439,002
Nuclear decommissioning fund and other investments	732,908	651,086
Regulatory assets	524,261	566,727
Other	651,276	553,650
Total other assets	3,367,855	3,210,465
Total assets	$21,768,843	$18,070,358
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current portion of long-term debt	$ 603,611	$ 431,049
Short-term debt	1,475,072	1,432,686
Accounts payable	1,608,989	793,139
Taxes accrued	236,837	260,676
Dividends payable	128,983	127,568
Other	618,316	438,101
Total current liabilities	4,671,808	3,483,219
DEFERRED CREDITS AND OTHER LIABILITIES:		
Deferred income taxes	1,794,193	1,779,046
Deferred investment tax credits	198,108	214,008
Regulatory liabilities	494,566	442,204
Benefit obligations and other	588,288	420,140
Total deferred credits and other liabilities	3,075,155	2,855,398
Minority interest in subsidiaries	277,335	14,696
CAPITALIZATION (SEE STATEMENTS OF CAPITALIZATION):		
Long-term debt	7,583,441	5,827,485
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 6)	494,000	494,000
Preferred stockholders' equity	105,320	105,340
Common stockholders' equity	5,561,784	5,290,220
COMMITMENTS AND CONTINGENCIES (SEE NOTE 14)		
Total liabilities and equity	$21,768,843	$18,070,358

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*Par Value*	*Premium*	*Retained Earnings*	*Shares Held by ESOP*	*Accumulated Other Comprehensive Income*	*Total Stockholders' Equity*
BALANCE AT DEC. 31, 1997	$802,245	$1,972,223	$2,023,925	$(10,533)	$ (58,745)	$4,729,115
Net income			624,330			624,330
Unrealized loss from marketable securities, net of tax of $4,417					(6,416)	(6,416)
Currency translation adjustments					(16,089)	(16,089)
Other comprehensive income for 1998						601,825
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(5,548)			(5,548)
Common stock			(475,399)			(475,399)
Issuances of common stock – net	23,150	223,985				247,135
Pooling of interests business combinations			6,065			6,065
Tax benefit from stock options exercised		850				850
Loan to ESOP to purchase shares*				(15,000)		(15,000)
Repayment of ESOP loan*				7,030		7,030
BALANCE AT DEC. 31, 1998	$825,395	$2,197,058	$2,173,373	$(18,503)	$ (81,250)	$5,096,073
Net income			570,933			570,933
Recognition of unrealized loss from marketable securities, net of tax of $4,417					6,416	6,416
Currency translation adjustments					(3,587)	(3,587)
Other comprehensive income for 1999						573,762
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(5,292)			(5,292)
Common stock			(489,813)			(489,813)
Issuances of common stock – net	12,930	92,247				105,177
Pooling of interests business combinations			4,599			4,599
Tax benefit from stock options exercised		58				58
Other	(132)	(1,109)				(1,241)
Repayment of ESOP loan*				6,897		6,897
BALANCE AT DEC. 31, 1999	$838,193	$2,288,254	$2,253,800	$(11,606)	$ (78,421)	$5,290,220
Net income			526,828			526,828
Currency translation adjustments					(78,508)	(78,508)
Other comprehensive income for 2000						448,320
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(4,241)			(4,241)
Common stock			(492,183)			(492,183)
Issuances of common stock – net	13,892	102,785				116,677
Tax benefit from stock options exercised		53				53
Other			16			16
Gain recognized from NRG stock offering		215,933				215,933
Loan to ESOP to purchase shares				(20,000)		(20,000)
Repayment of ESOP loan*				6,989		6,989
BALANCE AT DEC. 31, 2000	$852,085	$2,607,025	$2,284,220	$(24,617)	$(156,929)	$5,561,784

**Did not affect cash flows*

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*December 31* 2000	1999
LONG-TERM DEBT		
NSP-MINNESOTA DEBT		
First Mortgage Bonds, Series due:		
Dec. 1, 2000–2006, 3.50–4.10%	$ 13,230*	$ 15,170*
Dec. 1, 2000, 5.75%		100,000
Oct. 1, 2001, 7.875%	150,000	150,000
March 1, 2003, 5.875%	100,000	100,000
April 1, 2003, 6.375%	80,000	80,000
Dec. 1, 2005, 6.125%	70,000	70,000
April 1, 2007, 6.80%		60,000**
March 1, 2011, variable rate, 5.05% at Dec. 31, 2000, and 5.75% at Dec. 31,1999	13,700**	13,700**
March 1, 2019, variable rate, 4.25% at Dec. 31, 2000, and 3.7% at Dec. 31,1999	27,900**	27,900**
Sept. 1, 2019, variable rate, 4.36% and 4.61% at Dec. 31, 2000, and 3.71% at Dec. 31, 1999	100,000**	100,000**
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
Guaranty Agreements, Series due: Feb. 1, 1999–May 1, 2003, 5.375–7.40%	29,950**	30,650**
NSP-Minnesota Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
City of Becker Pollution Control Revenue Bonds – Series due Dec. 1, 2005, 7.25%		9,000**
City of Becker Pollution Control Revenue Bonds – Series due April 1, 2030, 5.1% at Dec. 31, 2000	69,000**	
Anoka County Resource Recovery Bond – Series due Dec. 1, 2000–2008, 4.05–5.0%	17,990	19,615*
Employee Stock Ownership Plan Bank Loans due 2000–2007, variable rate	24,617	11,606
Other	194	1,458
Unamortized discount – net	(5,513)	(6,604)
Total	1,341,068	1,432,495
Less redeemable bonds classified as current (See Note 4)	141,600	141,600
Less current maturities	161,773	108,509
Total NSP-Minnesota long-term debt	$1,037,695	$1,182,386
PSCO DEBT		
First Mortgage Bonds, Series due:		
Jan. 1, 2001, 6.00%	$ 102,667	$ 102,667
April 15, 2003, 6.00%	250,000	250,000
March 1, 2004, 8.125%	100,000	100,000
Nov. 1, 2005, 6.375%	134,500	134,500
June 1, 2006, 7.125%	125,000	125,000
April 1, 2008, 5.625%	18,000**	18,000**
June 1, 2012, 5.5%	50,000**	50,000**
April 1, 2014, 5.875%	61,500**	61,500**
Jan. 1, 2019, 5.1%	48,750**	48,750**
July 1, 2020, 9.875%		70,000
March 1, 2022, 8.75%	147,840	148,000
Jan. 1, 2024, 7.25%	110,000	110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000
Secured Medium-Term Notes, due Feb. 1, 2001–March 5, 2007, 6.45–9.25%	226,500	256,500
Other secured long-term debt 13.25%, due in installments through Oct. 1, 2016	29,777	30,298
PSCCC Unsecured Medium-Term Notes due May 30, 2000, 5.86%		100,000
PSCCC Unsecured Medium-Term Notes due May 30, 2002, variable rate 7.40% at Dec. 31, 2000	100,000	
Unamortized discount	(5,952)	(6,998)
Capital lease obligations, 11.2% due in installments through May 31, 2025	54,202	56,565
Total	1,752,784	1,854,782
Less current maturities	142,043	132,823
Total PSCo long-term debt	$1,610,741	$1,721,959

**Resource recovery financing*

***Pollution control financing*

See Notes to Consolidated Financial Statements

(Thousands of dollars)	December 31 2000	1999
LONG-TERM DEBT – CONTINUED		
SPS DEBT		
First Mortgage Bonds, Series due:		
July 15, 2004, 7.25%		$ 135,000
March 1, 2006, 6.5%		60,000
July 15, 2022, 8.25%		36,000
Dec. 1, 2022, 8.20%		89,000
Feb. 15, 2025, 8.50%		60,267
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ 100,000	100,000
Pollution control obligations, securing pollution control revenue bonds,		
Not collateralized by First Mortgage Bonds due:		
July 1, 2011, 5.20%	44,500	44,500
July 1, 2016, variable rate, 5.10% at Dec. 31, 2000 and 4.7% at Dec. 31, 1999	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Less: funds held by Trustee:	(168)	(168)
Unamortized discount	(126)	(1,024)
Total SPS long-term debt	$ 226,506	$ 605,875
NSP-WISCONSIN DEBT		
First Mortgage Bonds Series due:		
Oct. 1, 2003, 5.75%	$ 40,000	$ 40,000
March 1, 2023, 7.25%	110,000	110,000
Dec. 1, 2026, 7.375%	65,000	65,000
City of La Crosse Resource Recovery Bond – Series due Nov. 1, 2021, 6%	18,600*	18,600*
Fort McCoy System Acquisition – due Oct. 31, 2030, 7%	996	
Senior Notes – due Oct. 1, 2008, 7.64%	80,000	
Unamortized discount	(1,562)	(1,650)
Total	313,034	231,950
Less current maturities	34	
Total NSP-Wisconsin long-term debt	$ 313,000	$ 231,950
NRG DEBT		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 239,386	
NRG Energy, Inc. Senior Notes, Series due		
Feb. 1, 2006, 7.625%	125,000	$ 125,000
June 15, 2007, 7.5%	250,000	250,000
June 1, 2009, 7.5%	300,000	300,000
Nov. 1, 2013, 8%	240,000	240,000
Sept. 15, 2010, 8.25%	350,000	
NRG debt secured solely by project assets:		
NRG Northeast Generating debt		646,564
NRG Northeast Generating Senior Bonds, Series due		
Dec. 15, 2004, 8.065%	270,000	
June 15, 2015, 8.842%	130,000	
Dec. 15, 2024, 9.292%	300,000	
South Central Generating Senior Bonds, Series due		
May 15, 2016, 8.962%	488,750	
Sept. 15, 2024, 9.479%	300,000	
Sterling Luxembourg #3 Loan due June 30, 2019, variable rate, 7.86% at Dec. 31, 2000	346,668	
Flinders Power Finance Pty. due September 2012, various rates, 7.58% at Dec. 31, 2000	83,820	
Crockett Corp. LLP debt due Dec. 31, 2014, 8.13%	245,229	255,000
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	65,762	68,881
Various debt due 2001–2008 , 0.0–10.73%	60,923	62,072
Other	1,307	18,631
Total	3,796,845	1,966,148
Less current maturities	145,504	30,524
Total NRG long-term debt	$3,651,341	$1,935,624

**Resource recovery financing*

See Notes to Consolidated Financial Statements

(Thousands of dollars)	December 31 2000	1999
LONG-TERM DEBT – CONTINUED		
OTHER SUBSIDIARIES' LONG-TERM DEBT		
First Mortgage Bonds – Cheyenne:		
Series due April 1, 2003–Jan. 1, 2024, 7.5–7.875%	$ 12,000	$ 12,000
Industrial Development Revenue Bonds due Sept. 1, 2021–March 1, 2027, variable rate 4.95% and 5.60% at Dec. 31, 2000 and 1999	17,000	17,000
Viking Gas Transmission Co. Senior Notes – Series due Oct. 31, 2008–Sept. 30, 2014, 6.65–8.04%	49,941	54,702
Various Eloigne Co. Affordable Housing Project Notes due 2002–2024, 0.3–9.91%	51,309	47,116
Other	30,414	36,466
Total	160,664	167,284
Less current maturities	12,657	17,593
Total other subsidiaries long-term debt	$ 148,007	$ 149,691
XCEL ENERGY INC. DEBT		
Unsecured Senior Notes due Dec. 1, 2010, 7%	$ 600,000	
Unamortized discount	(3,849)	
Total Xcel Energy Inc. debt	$ 596,151	
Total long-term debt	$7,583,441	$5,827,485
MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS		
Each holding as its sole asset junior subordinated deferrable debentures of NSP-Minnesota, PSCo and SPS – (see Note 6)	$ 494,000	$ 494,000
CUMULATIVE PREFERRED STOCK – authorized 7,000,000 shares of $100 par value; outstanding shares: 2000, 1,049,800; 1999, 1,050,000		
$3.60 series, 275,000 shares	$ 27,500	$ 27,500
4.08 series, 150,000 shares	15,000	15,000
4.10 series, 175,000 shares	17,500	17,500
4.11 series, 200,000 shares	20,000	20,000
4.16 series, 2000, 99,800 shares; 1999, 100,000 shares	9,980	10,000
4.56 series, 150,000 shares	15,000	15,000
Total	104,980	105,000
Premium on preferred stock	340	340
Total preferred stockholders' equity	$ 105,320	$ 105,340
COMMON STOCKHOLDERS' EQUITY		
Common stock – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2000, 340,834,147; 1999, 335,277,321	$ 852,085	$ 838,193
Premium on common stock	2,607,025	2,288,254
Retained earnings	2,284,220	2,253,800
Leveraged common stock held by ESOP – shares at cost: 2000, 1,041,180; 1999, 392,325	(24,617)	(11,606)
Accumulated other comprehensive income (loss)	(156,929)	(78,421)
Total common stockholders' equity	$5,561,784	$5,290,220

See Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Merger Basis of Presentation

On Aug. 18, 2000, following receipt of all required regulatory approvals, NSP and NCE merged and formed Xcel Energy Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares) and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA.

Pursuant to the merger agreement, NCE was merged with and into NSP. NSP, as the surviving legal corporation, changed its name to Xcel Energy. Also, as part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed wholly owned subsidiary of Xcel Energy, which was renamed NSP-Minnesota.

Consistent with pooling accounting requirements, results and disclosures for all periods prior to the merger have been restated for consistent reporting with post-merger organization and operations. All earnings per share amounts previously reported for NSP and NCE have been restated for presentation on an Xcel Energy share basis.

Business and System of Accounts

Xcel Energy's domestic utility subsidiaries are engaged principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. Xcel Energy and its subsidiaries are subject to the regulatory provisions of the PUHCA. The utility subsidiaries are subject to regulation by the FERC and state utility commissions. All of the utility companies' accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material aspects.

Principles of Consolidation

Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, BMG and Cheyenne. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy's regulated businesses also include Viking and WGI.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., a publicly traded independent power producer. Xcel Energy indirectly owns 82 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter 2000, when NRG completed its initial public offering.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Seren Innovations, Inc., e prime, inc., Planergy International, Inc. and Eloigne Company. Xcel Energy also reports in its nonregulated activities its 50-percent stake in Yorkshire Power.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Energy Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc. and Xcel Energy O & M Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects. We record our portion of earnings from international investments after subtracting foreign income taxes, if applicable. In the consolidation process, we eliminate all significant intercompany transactions and balances.

Revenue Recognition

Xcel Energy records utility revenues based on a calendar month, but reads meters and bills customers according to a cycle that doesn't necessarily correspond with the calendar month's end. To compensate, we estimate and record unbilled revenues from the monthly meter-reading dates to the month's end.

Xcel Energy's utility subsidiaries have adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred.

PSCo's electric rates in Colorado are adjusted under the ICA, which takes into account changes in energy costs and certain trading gains and losses that are shared with the customer. SPS' rates in Texas and New Mexico have periodic fuel filing and reporting requirements, which can provide cost recovery. NSP-Wisconsin's rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. In Wisconsin, we can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel cost hearing process.

In Colorado, PSCo operates under an electric PBRP, which results in an annual earnings test with the sharing of excess earnings between customers and shareholders. The sharing threshold is earnings in excess of an 11-percent return on equity for 2001 and a 10.50-percent return on equity for 2002. In Texas, SPS operates under an earnings tests, in which excess earnings above a certain level are returned to the customer.

NSP-Minnesota and PSCo's rates include monthly adjustments for the recovery of conservation and energy management program costs, which are reviewed annually.

Trading Operations

Effective with year-end 2000 reporting, Xcel Energy changed its policy for the presentation of energy trading operating results. Previously, trading margins were recorded net of costs in electric and natural gas revenues. After the merger, Xcel Energy elected to report trading revenues separately from trading costs. Prior years' results have been reclassified for consistency with 2000 reporting.

Xcel Energy's trading operations are conducted mainly by PSCo and e prime. Trading revenues and costs of goods sold do not include the revenue and production costs associated with energy produced from generation assets or results from NRG.

Property, Plant, Equipment and Depreciation

Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired, plus net removal cost, is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Xcel Energy determines the depreciation of its plant by spreading the original cost equally over the plant's useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.3 percent for the years ended Dec. 31, 2000, 1999 and 1998.

Property, plant and equipment includes approximately $18 million and $25 million, respectively, for costs associated with the engineering design of the future Pawnee 2 generating station and certain water rights located in southeastern Colorado, also obtained for a future generating station. PSCo is earning a return on these investments based on its weighted average cost of debt in accordance with a CPUC rate order.

Allowance for Funds Used During Construction (AFDC)

AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other income and expense (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in Xcel Energy's rate base for establishing utility service rates. In addition to construction-related amounts, AFDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota. Interest capitalized as AFDC was approximately $20 million in 2000, $19 million in 1999 and $25 million in 1998.

Decommissioning

Xcel Energy accounts for the future cost of decommissioning – or permanently retiring – its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full-rate recovery of the future decommissioning costs. Our decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. For more information on nuclear decommissioning, see Note 15 to the Financial Statements.

Nuclear Fuel Expense

Nuclear fuel expense, which is recorded as the plant uses fuel, includes the cost of nuclear fuel used and future spent nuclear fuel disposal, based on fees established by the U.S. Department of Energy (DOE) and NSP-Minnesota's portion of the cost of decommissioning or shutting down the DOE's fuel enrichment facility.

Environmental Costs

We record environmental costs when it is probable Xcel Energy is liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flows.

We record estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Income Taxes

Xcel Energy and its subsidiaries file consolidated federal and combined and separate state income tax returns. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. We use the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which we summarize in Note 16 to the Financial Statements. We discuss our income tax policy for international operations in Note 8 to the Financial Statements.

Foreign Currency Translation

Xcel Energy's foreign operations generally use the local currency as their functional currency in translating international operating results and balances to U.S. currency. Foreign currency denominated assets and liabilities are translated at the exchange rates in effect at the end of a reporting period. Income, expense and cash flows are translated at weighted-average exchange rates for the period. We accumulate the resulting currency translation adjustments and report them as a component of Other Comprehensive Income. When we convert cash distributions made in one currency to another currency, we include those gains and losses in the results of operations as a component of other income.

Derivative Financial Instruments

Xcel Energy and its subsidiaries utilize a variety of derivatives, including interest rate swaps and locks, foreign currency hedges and energy contracts. The energy contracts are both financial- and commodity-based, in the energy trading and energy non-trading operations, to reduce exposure to commodity price risk. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps.

Xcel Energy and its subsidiaries adopted Emerging Issues Task Force (EITF) 98-10, "Accounting for Energy Trading and Risk Management Activities," effective Jan. 1, 1999. EITF 98-10 requires gains or losses resulting from market value changes on energy trading contracts to be recorded in earnings. The initial adoption of EITF 98-10 had an immaterial impact on Xcel Energy's net income.

Energy contracts also are utilized by Xcel Energy and its subsidiaries in non-trading operations to reduce commodity price risk. Hedge accounting is applied only if the contract reduces the price risk of the underlying hedged item and is designated as a hedge at its inception. Gains and losses related to qualifying hedges of firm commitments or anticipated transactions are deferred and recognized as a component of purchased power or cost of gas sold when settlement occurs. If, subsequent to the inception of the hedge, the underlying transactions are no longer likely to occur, the related gains and losses are recognized currently in income.

While NRG is not currently hedging investments involving foreign currency, NRG will hedge such investments when it believes that preserving the U.S. dollar value of the investment is appropriate. NRG is not hedging currency translation adjustments related to future operating results. NRG does not speculate in foreign currencies. Xcel Energy is not currently hedging its foreign currency exposure associated with its investment in Yorkshire Power.

From time to time, NRG also uses interest rate hedging instruments to protect it from an increase in the cost of borrowing. Gains and losses on interest rate hedging instruments are reported as part of the asset Investments in Unconsolidated Affiliates when the hedging instrument relates to a project that has financial statements that are not consolidated into NRG's financial statements. Otherwise, they are reported as a part of debt.

A final derivative instrument used by Xcel Energy is the interest rate swap. The cost or benefit of the interest rate swap agreements is recorded as a component of interest expense. None of these derivative financial instruments are reflected on Xcel Energy's balance sheet. For further discussion of Xcel Energy's risk management and derivative activities, see Note 13 to the Financial Statements.

Use of Estimates

In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. We use estimates for such items as plant depreciable lives, tax provisions, uncollectible amounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results. Each year we also review the depreciable lives of certain plant assets and revise them if appropriate.

Cash Equivalents

Xcel Energy considers investments in certain debt instruments – with a remaining maturity of three months or less at the time of purchase – to be cash equivalents. Those debt instruments are primarily commercial paper and money market funds.

Inventory

All inventory is recorded at average cost, with the exception of natural gas in underground storage at PSCo, which is recorded using last-in-first-out (LIFO) pricing.

Regulatory Accounting

Xcel Energy's regulated utility subsidiaries account for certain income and expense items using SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation." As discussed in Note 12 to the Financial Statements, SPS' generation business no longer follows SFAS 71. Under SFAS 71:

- We defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and
- We defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific rate-making decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment.

Stock-Based Employee Compensation

Xcel Energy has several stock-based compensation plans. We account for those plans using the intrinsic value method. We do not record compensation expense for stock options because there is no difference between the market price and the purchase price at grant date. We do, however, record compensation expense for restricted stock that we award to certain employees, but hold until the restrictions lapse or the stock is forfeited. We do not use the optional accounting under SFAS No. 123 – "Accounting for Stock-Based Compensation." If we had used the SFAS 123 method of accounting, earnings would have been reduced by approximately 2 cents per share for 2000 and approximately 1 cent per share per year for 1999 and 1998.

NRG Development Costs

As NRG develops projects, it expenses the development costs it incurs until a sales agreement or letter of intent is signed and the project has received NRG board approval. NRG capitalizes additional costs incurred at that point. When a project begins to operate, NRG amortizes the capitalized costs over either the life of the project's related assets or the revenue contract period, whichever is less. If a project is terminated without becoming operational, NRG expenses the capitalized costs in the period of the termination.

Intangible Assets and Deferred Financing Costs

Goodwill results when Xcel Energy purchases an entity at a price higher than the underlying fair value of the net assets. We amortize the goodwill and other intangible assets over periods consistent with the economic useful life of the assets. Our intangible assets are currently amortized over a range of 5 to 40 years. We periodically evaluate the recovery of goodwill based on an analysis of estimated undiscounted future cash flows. At Dec. 31, 2000, Xcel Energy's intangible assets included approximately $66 million of goodwill, net of $7 million of accumulated amortization.

Intangible and other assets also included deferred financing costs, net of amortization, of approximately $94 million at Dec. 31, 2000. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Reclassifications

We reclassified certain items in the 1998 and 1999 income statements and the 1999 balance sheet to conform to the 2000 presentation. These reclassifications had no effect on net income or earnings per share. Reported amounts for periods prior to the merger have been restated to reflect the merger as if it had occurred as of Jan. 1, 1998.

2. MERGER COSTS AND SPECIAL CHARGES

Special Charges 2000

Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million. In the aggregate, these special charges reduced Xcel Energy's 2000 earnings by 52 cents per share. Of these pretax special charges, $201 million, or 43 cents per share, was recorded during the third quarter of 2000, and $40 million, or 9 cents per share, was recorded during the fourth quarter of 2000.

The pretax charges included $52 million related to one-time transaction-related costs incurred in connection with the merger of NSP and NCE. These transaction costs include investment banker fees, legal and regulatory approval costs, and expenses for support of and assistance with planning and completing the merger transaction.

Also included were $147 million of pretax charges pertaining to incremental costs of transition and integration activities associated with merging NSP and NCE to begin operations as Xcel Energy. These transition costs include approximately $77 million for severance and related expenses associated with staff reductions of 721 employees, 661 of whom were released through February 2001. The staff reductions were non-bargaining positions mainly in corporate and operations support areas. Other transition and integration costs include amounts incurred for facility consolidation, systems integration, regulatory transition, merger communications and operations integration assistance.

In addition, the pretax charges include $42 million of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy's nonregulated businesses. These special charges, which were recorded in the third quarter, include: $22 million of write-offs of goodwill and project development costs for Planergy and Energy Masters International (EMI) energy services operations due to a change in their business focus and direction after the merger; $10 million of contractual obligations and other costs associated with post-merger changes in the strategic operations and related revaluations of e prime's energy marketing business; and $10 million in asset write-downs and losses resulting from various other nonregulated business ventures that would not be pursued after the merger. The write-downs were based on fair value estimates, consisting mainly of future cash flow projections.

The pretax special charges recognized for merger transaction, transition and integration activities include approximately $66 million in costs incurred prior to third quarter 2000, which had been deferred prior to merger consummation. Consistent with pooling accounting requirements, upon consummation of the merger to form Xcel Energy in the third quarter of 2000, Xcel Energy expensed all merger-related costs incurred up to that point.

The following table summarizes the special charges expensed during 2000.

	Expensed Without Accrual		*Expense Accrued as Liability*		*Payments Against Liability*		*Dec. 31, 2000*
(Millions of dollars)	*3rd Qtr.*	*4th Qtr.*	*3rd Qtr.*	*4th Qtr.*	*3rd Qtr.*	*4th Qtr.*	*Liability**
Employee separation and other related costs	$ 16	$ 3	$52	$6		$(10)	$48
Regulatory transition costs	4	2	5	1		(1)	5
Other transition and integration costs	33	23		2			2
Total merger transition and integration costs	53	28	57	9		(11)	55
Transaction-related merger costs	49	3					
Nonregulated asset disposals and abandonments	22						
Nonregulated goodwill impairment	20						
Total nonregulated asset impairments	42						
Total special charges	$144	$31	$57	$9		$(11)	$55

**Reported on the balance sheet in other current liabilities.*

Special Charges 1999

EMI Goodwill In December 1999, Xcel Energy recorded a pretax charge (reported in special charges) of approximately $17 million, or 4 cents per share, to write off all goodwill that was recorded by its subsidiary EMI for its acquisitions of Energy Masters Corp. in 1995 and Energy Solutions International in 1997. This charge reflected a revised business outlook based on the levels of contract signings by EMI.

Loss on Marketable Securities During 1999, Xcel Energy recorded pretax charges (reported in special charges) of approximately $14 million, or 3 cents per share, for valuation write-downs on its investment in the publicly traded common stock of CellNet Data Systems, Inc. In October 1999, CellNet announced it was experiencing financial difficulties and was contemplating restructuring its capital financing. In February 2000, CellNet filed for Chapter 11 bankruptcy protection. CellNet's assets were subsequently acquired by another company.

3. SHORT-TERM BORROWINGS

Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended Dec. 31, 2000 and 1999, is:

(Millions of dollars, except interest rates)	**2000**	**1999**
Notes payable to banks	$ 20	$ 399
Commercial paper	1,455	1,034
Total short-term debt	$1,475	$1,433
Weighted average interest rate at year end	6.48%	6.37%

Bank Lines of Credit and Compensating Bank Balances

At Dec. 31, 2000, Xcel Energy and its subsidiaries had approximately $3.0 billion in unsecured revolving credit facilities with several banks. Arrangements by Xcel Energy and its subsidiaries for committed lines of credit are maintained by a combination of fee payments and compensating balances.

In November 2000, Xcel Energy closed on two revolving credit facilities totaling $800 million. These facilities are comprised of a $400 million, 364-day maturity and a $400 million, five-year maturity. They are available for Xcel's general corporate purposes, primarily supporting commercial paper borrowings.

In July 2000, NSP-Minnesota closed on a $300 million, 364-day revolving credit facility. This facility provides short-term financing in the form of bank loans and letters of credit, but its primary purpose is support for commercial paper borrowings.

In July 2000, PSCo and its subsidiary, Public Service of Colorado Credit Corporation (PSCCC), entered into a $600 million, 364-day revolving credit agreement that provides for direct borrowings, but whose primary purpose is to support the issuance of commercial paper by PSCo and PSCCC.

In July 2000, SPS entered into a $500-million credit agreement that is effective through January 2002. This credit facility was initially used as support for the issuance of commercial paper to fund open market purchases, tender and defeasance of SPS' outstanding first mortgage bonds and other related restructuring costs. SPS is the initial borrower under this credit agreement; however, at the time of separation of the generation assets, the obligations under this credit agreement will be assumed by a newly formed generation company. See Note 12 to the Financial Statements for more information on restructuring.

In February 2001, SPS renewed a $300 million, 364-day revolving credit facility. This facility provides for direct borrowings, but its primary purpose is to support the issuance of commercial paper.

In January 2001, NRG entered into a $600-million bridge credit facility to provide financing for its LS Power acquisition. It is expected to be repaid with the proceeds of NRG's planned common stock and equity unit offerings. The credit facility expires Dec. 31, 2001.

NRG has a $500-million revolving credit facility under a commitment fee arrangement that matures in March 2001. This facility provides short-term financing in the form of bank loans. At Dec. 31, 2000, NRG had $8 million outstanding under this facility.

NRG has a $125-million syndicated letter of credit facility that matures in November 2003. At Dec. 31, 2000, NRG had $58 million outstanding under this facility.

4. LONG-TERM DEBT

Except for SPS and other minor exclusions, all property of Xcel Energy's utility subsidiaries is subject to the liens of its first mortgage indentures, which are contracts between the companies and their bond holders. In addition, certain SPS payments under its pollution control obligations are pledged to secure obligations of the Red River Authority of Texas.

The annual sinking-fund requirements of Xcel Energy's utility subsidiaries' first mortgage indentures are the amounts necessary to redeem 1 to 1.5 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding series issued for pollution control and resource recovery financings and certain other series totaling $2 billion.

NSP-Minnesota, NSP-Wisconsin, PSCo and Cheyenne expect to satisfy substantially all of their sinking-fund obligations in accordance with the terms of their respective indentures through the application of property additions. SPS has no significant sinking-fund requirements.

NSP-Minnesota's 2011 and 2019 series first mortgage bonds have variable interest rates, which currently change at various periods up to 270 days, based on prevailing rates for certain commercial paper securities or similar issues. The 2011 series bonds are redeemable upon seven-days notice at the option of the bondholder. NSP-Minnesota also is potentially liable for repayment of the 2019 series when the bonds are tendered, which occurs each time the variable interest rates change. The principal amount of all of these variable rate bonds outstanding represents potential short-term obligations and, therefore, is reported under current liabilities on the balance sheets.

Maturities and sinking-fund requirements for Xcel Energy's long-term debt are:

- 2001 $605 million
- 2002 $311 million
- 2003 $663 million
- 2004 $267 million
- 2005 $286 million

5. PREFERRED STOCK

At Dec. 31, 2000, Xcel Energy had various preferred stock series, which were callable at prices per share ranging from $102 to $103.75, plus accrued dividends.

PSCo has 10 million shares of cumulative preferred stock, $0.01 par value, authorized. At Dec. 31, 2000 and 1999, PSCo had no shares of preferred stock outstanding.

SPS has 10 million shares of cumulative preferred stock, $1 par value, authorized. At Dec. 31, 2000 and 1999, SPS had no shares of preferred stock outstanding.

6. MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

In 1996, SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, issued $100 million of 7.85 percent trust preferred securities that mature in 2036. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by SPS and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. Distributions and redemption payments are guaranteed by SPS.

In 1997, NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, issued $200 million of 7.875 percent trust preferred securities that mature in 2037. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by NSP-Minnesota and held by the subsidiary trust, which are eliminated in consolidation. The preferred securities are redeemable at $25 per share beginning in 2002. Distributions and redemption payments are guaranteed by NSP-Minnesota.

In 1998, PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, issued $194 million of 7.60 percent trust preferred securities that mature in 2038. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by PSCo and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of PSCo after May 2003, at 100 percent of the principal amount outstanding plus accrued interest. Distributions and redemption payments are guaranteed by PSCo.

Distributions paid to preferred security holders are reflected as a financing cost in the Consolidated Income Statements along with interest expense.

7. JOINT PLANT OWNERSHIP

The investments by Xcel Energy's utility subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2000, are as follows:

(Thousands of dollars)	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NSP-MINNESOTA – Sherco Unit 3	$607,568	$252,096	$1,095	59.0
PSCO:				
Hayden Unit 1	82,800	35,767	1,172	75.5
Hayden Unit 2	78,347	39,058	161	37.4
Hayden Common Facilities	27,145	2,071	258	53.1
Craig Units 1 & 2	57,710	29,248		9.7
Craig Common Facilities Units 1, 2 & 3	21,012	8,339	(21)	6.5–9.7
Transmission Facilities, including Substations	81,769	27,349	609	42.0–73.0
Total PSCo	$348,783	$141,832	$2,179	
NRG – Big Cajun II, Unit 3	$179,100	$ 3,400		58.0

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt coal-fired electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of related expenses for Sherco 3 is included in Utility Operating Expenses. The PSCo assets include approximately 320 megawatts of generating capacity. PSCo is responsible for its proportionate share of operating expenses (reflected in the Consolidated Statements of Income) and construction expenditures. NRG is responsible for its proportionate share of operating expenses and construction expenditures.

8. INCOME TAXES

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The reasons for the difference are:

	2000	1999	1998
Federal statutory rate	35.0%	35.0%	35.0%
INCREASES (DECREASES) IN TAX FROM:			
State income taxes, net of federal income tax benefit	5.8%	2.1%	2.8%
Life insurance policies	(2.4)%	(2.3)%	(1.7)%
Tax credits recognized	(10.2)%	(6.0)%	(4.6)%
Equity income from unconsolidated affiliates	(2.7)%	(5.5)%	(4.9)%
Regulatory differences – utility plant items	2.3%	1.9%	1.0%
Deferred tax expense on Yorkshire investment	2.3%		
Non-deductibility of merger costs	2.9%		
Other – net	1.8%	(1.3)%	0.2%
Effective income tax rate including extraordinary items	34.8%	23.9%	27.8%
Extraordinary items	1.0%		
Effective income tax rate excluding extraordinary items	35.8%	23.9%	27.8%

(Thousands of dollars)	2000	1999	1998
INCOME TAXES COMPRISE THE FOLLOWING EXPENSE (BENEFIT) ITEMS:			
Current federal tax expense	$205,718	$175,461	$238,124
Current state tax expense	63,428	26,949	34,454
Current foreign tax expense	(625)	4,040	2,358
Current federal tax credits	(71,270)	(30,137)	(25,122)
Deferred federal tax expense	103,258	27,380	9,940
Deferred state tax expense	12,547	(2,352)	3,027
Deferred foreign tax expense	7,104	(6,868)	(7,736)
Deferred investment tax credits	(15,295)	(14,800)	(14,654)
Income tax expense excluding extraordinary items	304,865	179,673	240,391
Tax expense on extraordinary items	8,549		
Total income tax expense	$296,316	$179,673	$240,391

Xcel Energy management intends to indefinitely reinvest earnings from NRG's foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $238 million and $195 million at Dec. 31, 2000 and 1999. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

Xcel Energy does not intend to indefinitely reinvest earnings from its investment in Yorkshire Power and, therefore, has provided deferred taxes of $20 million on unremitted earnings of $55 million at Dec. 31, 2000. Prior to 2000, management did intend to reinvest Yorkshire Power earnings indefinitely, and thus no taxes were provided on unremitted earnings of $11 million at Dec. 31, 1999.

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

(Thousands of dollars)	2000	1999
DEFERRED TAX LIABILITIES:		
Differences between book and tax bases of property	$1,754,928	$1,739,394
Regulatory assets	168,380	143,187
Partnership income/loss	70,266	36,756
Tax benefit transfer leases	18,839	23,431
Other	98,263	106,932
Total deferred tax liabilities	$2,110,676	$2,049,700
DEFERRED TAX ASSETS:		
Regulatory liabilities	$ 88,817	$ 71,471
Employee benefits	14,675	13,493
Deferred investment tax credits	76,133	83,061
Other	87,116	103,041
Total deferred tax assets	$ 266,741	$ 271,066
Net deferred tax liability	$1,843,935	$1,778,634

9. COMMON STOCK AND INCENTIVE STOCK PLANS

Incentive Stock Plans

We and some of our subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate our earnings per share includes the dilutive effect of stock options and other stock awards based on the treasury stock method. The tables below include awards made by us and some of our predecessor companies. Stock options issued under NCE, PSCo and SPS plans before the merger have been adjusted for the merger stock exchange ratio and are presented on an Xcel Energy share basis.

	2000		1999		1998	
Stock Options and Performance Awards at Dec. 31, 2000 (Thousands)	*Awards*	*Average Price*	*Awards*	*Average Price*	*Awards*	*Average Price*
Outstanding at beginning of year	8,490	$25.12	6,156	$26.15	5,439	$24.92
Granted	6,980	25.31	2,545	22.64	1,456	29.19
Exercised	(453)	20.33	(90)	18.72	(636)	22.36
Forfeited	(704)	25.70	(111)	30.10	(94)	28.15
Expired	(54)	22.62	(10)	25.64	(9)	23.24
Outstanding at end of year	14,259	$25.35	8,490	$25.12	6,156	$26.15
Exercisable at end of year	8,221	$24.46	5,301	$25.84	4,405	$25.14

	Range of Exercise Prices		
at Dec. 31, 2000	*$16.60 to $21.75*	*$22.50 to $27.99*	*$28.00 to $31.00*
Options outstanding:*			
Number outstanding	3,245,478	9,616,092	1,388,878
Weighted average remaining contractual life (years)	7.6	8.3	7.4
Weighted average exercise price	$19.82	$26.44	$30.67
Options exercisable:*			
Number exercisable	2,820,681	4,212,023	1,180,324
Weighted average exercise price	$19.78	$25.86	$30.65

**There were also 8,259 other awards outstanding at Dec. 31, 2000.*

Certain employees also may be awarded restricted stock under Xcel Energy's incentive plans. We hold restricted stock until restrictions lapse; 50 percent of the stock vests one year from the date of the award and the other 50 percent vests two years from the date of the award. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment. We granted 58,690 restricted shares in 2000, 52,688 restricted shares in 1999 and 49,651 restricted shares in 1998. Compensation expense related to these awards was immaterial.

The NCE/NSP merger was a "change in control" under the NSP incentive plan, so all stock option and restricted stock awards under that plan became fully vested and exercisable as of the merger date. The NCE/NSP merger did not constitute a change in control under the NCE incentive plans, so there was no accelerated vesting of stock options issued under them. When NCE and NSP merged, each outstanding NCE stock option was converted to 1.55 Xcel Energy options.

We apply Accounting Principles Board Opinion No. 25 in accounting for its stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options as the exercise price of the options equals the fair-market value of our common stock at the date of grant. If we had used the SFAS 123 method of accounting, earnings would have been reduced by approximately 2 cents per share for 2000 and approximately 1 cent per share per year for 1999 and 1998.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes Option-Pricing Model with the following assumptions:

	2000	1999	1998
Expected option life	3–5 years	5–10 years	5–10 years
Stock volatility	15%	15–21%	14–15%
Risk-free interest rate	5.3–6.5%	4.7–6.4%	5.1–5.6%
Dividend yield	5.4–7.5%	5.4%	5.2–5.4%

Dividend Restrictions

The Articles of Incorporation of both NSP-Minnesota and Xcel Energy place restrictions on the amount of common stock dividends they can pay when preferred stock is outstanding. NSP-Minnesota has no outstanding preferred stock, so these restrictions would not apply. Xcel Energy has outstanding preferred stock. It could have paid approximately $2.75 billion in additional common stock dividends before restrictions would apply.

In addition, NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $800 million in additional cash dividends on common stock at Dec. 31, 2000.

Shareholder Rights

In 2000, Xcel Energy adopted a shareholder protection rights plan. This rights plan is subject to approval by the SEC. The plan is designed to protect shareholders' interests in the event we are ever confronted with an unfair or inadequate acquisition proposal. Pursuant to this plan and assuming SEC approval, each share of common stock has one right entitling the holder to purchase a share of Xcel Energy common stock under certain circumstances. The rights become exercisable if any person or group acquires 15 percent or more of Xcel Energy's common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of Xcel Energy common stock or common stock of any acquirer of Xcel Energy at a reduced percentage of market value. The rights are scheduled to expire in 2011.

10. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 45 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2000, NSP-Minnesota and NSP-Wisconsin had 2,598 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 1,969 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 776 union employees covered under a collective-bargaining agreement, which expires in October 2002.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility employees. Benefits are based on a combination of years of service, the employee's average pay and Social Security benefits.

Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities.

A comparison of the actuarially computed pension benefit obligation and plan assets at Dec. 31, 2000 and 1999, for all Xcel Energy plans on a combined basis is presented in the following table.

(Thousands of dollars)	2000	1999
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	$2,170,627	$2,157,255
Service cost	59,066	63,674
Interest cost	172,063	154,619
Acquisitions	52,800	
Plan amendments	2,649	184,255
Actuarial (gain) loss	1,327	(225,355)
Benefit payments	(204,394)	(163,821)
Obligation at Dec. 31	$2,254,138	$2,170,627
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	$3,763,293	$3,460,740
Actual return on plan assets	91,846	466,374
Acquisitions	38,412	
Benefit payments	(204,394)	(163,821)
Fair value of plan assets at Dec. 31	$3,689,157	$3,763,293
FUNDED STATUS AT DEC. 31		
Net asset	$1,435,019	$1,592,666
Unrecognized transition (asset) obligation	(16,631)	(23,945)
Unrecognized prior-service cost	228,436	247,632
Unrecognized (gain) loss	(1,421,690)	(1,680,616)
Prepaid pension asset recorded	$ 225,134	$ 135,737

	2000	1999
SIGNIFICANT ASSUMPTIONS		
Discount rate	7.75%	7.5–8.0%
Expected long-term increase in compensation level	4.50%	4.0–4.5%
Expected average long-term rate of return on assets	8.5–10.0%	8.5–10.0%

The components of net periodic pension cost (credit) for Xcel Energy plans are:

(Thousands of dollars)	2000	1999	1998
Service cost	$ 59,066	$ 63,674	$ 55,545
Interest cost	172,063	154,619	145,574
Expected return on plan assets	(292,580)	(259,074)	(233,191)
Amortization of transition asset	(7,314)	(7,314)	(7,314)
Amortization of prior-service cost	19,197	17,855	6,209
Amortization of net gain	(60,676)	(40,217)	(30,607)
Net periodic pension cost (credit) under SFAS 87	$(110,244)	$ (70,457)	$ (63,784)
Credits not recognized due to effects of regulation	49,697	36,469	35,545
Net benefit cost (credit) recognized for financial reporting	$ (60,547)	$ (33,988)	$ (28,239)

Additionally, Xcel Energy maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $23 million in 2000 and $21 million annually in 1999 and 1998.

Xcel Energy has a leveraged ESOP that covers substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy makes contributions to this noncontributory, defined contribution plan to the extent we realize a tax savings from dividends paid on certain ESOP shares. ESOP contributions have no material effect on Xcel Energy earnings because the contributions are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocates leveraged ESOP shares to participants when it repays ESOP loans with dividends on stock held by the ESOP.

Xcel Energy's leveraged ESOP held 12.0 million shares of Xcel Energy common stock at the end of 2000 and 11.3 million shares of Xcel Energy common stock at the end of 1999 and 1998. Xcel Energy excluded the following uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2000, 0.5 million in 1999 and 0.6 million in 1998.

Postretirement Health Care Benefits

Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees. The NSP plan was terminated for nonbargaining employees retiring after 1998 and for bargaining employees after 1999.

In conjunction with the 1993 adoption of SFAS No.106 – "Employers' Accounting for Postretirement Benefits Other Than Pensions," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS 106. PSCo transitioned to full accrual accounting for SFAS 106 costs between 1993 and 1997, consistent with the accounting requirements for rate regulated enterprises. The Colorado jurisdictional SFAS 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS 106 costs, with regulatory differences fully amortized prior to 1997.

Additionally, certain state agencies, which regulate Xcel Energy's utility subsidiaries, have issued guidelines related to the funding of SFAS 106 costs. SPS is required to fund SFAS 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo and Cheyenne are required to fund SFAS 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Minnesota and Wisconsin retail regulators require external funding of accrued SFAS 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed income securities and cash equivalents.

A comparison of the actuarially computed benefit obligation and plan assets at Dec. 31, 2000 and 1999, for all Xcel Energy postretirement health care plans is presented in the following table.

(Thousands of dollars)	2000	1999
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	$533,458	$616,957
Service cost	5,679	4,680
Interest cost	43,477	35,583
Acquisitions	16,445	
Plan amendments		(80,840)
Plan participants' contributions	4,358	3,818
Actuarial (gain) loss	10,501	(5,581)
Benefit payments	(37,191)	(41,159)
Obligation at Dec. 31	$576,727	$533,458
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	$201,767	$180,742
Actual return on plan assets	10,069	11,981
Plan participants' contributions	4,358	3,818
Employer contributions	44,263	34,652
Benefit payments	(37,191)	(29,426)
Fair value of plan assets at Dec. 31	$223,266	$201,767
FUNDED STATUS AT DEC. 31		
Net obligation	$353,461	$331,691
Unrecognized transition asset (obligation)	(202,871)	(219,644)
Unrecognized prior-service credit	13,789	14,999
Unrecognized gain (loss)	(11,126)	5,559
Accrued benefit liability recorded	$153,253	$132,605

	2000	1999
SIGNIFICANT ASSUMPTIONS:		
Discount rate	7.75%	7.5–8.0%
Expected average long-term rate of return on assets	8.0–9.5%	8.0–9.5%

The assumed health care cost trend rate for 2000 is approximately 7.5 percent, decreasing gradually to 5.5 percent in 2004 and remaining level thereafter. A 1-percent increase in the assumed health care cost trend rate would increase the estimated total accumulated benefit obligation for Xcel Energy by approximately $49.3 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $3.8 million. A 1-percent decrease in the assumed health care cost trend rate would decrease the estimated total accumulated benefit obligation for Xcel Energy by approximately $42.9 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $3.3 million.

The components of net periodic postretirement benefit cost of all Xcel Energy's plans are:

(Thousands of dollars)	2000	1999	1998
Service cost	$ 5,679	$ 4,680	$ 8,164
Interest cost	43,477	35,583	42,399
Expected return on plan assets	(17,902)	(15,003)	(12,349)
Amortization of transition obligation	16,773	17,461	23,411
Amortization of prior-service cost (credit)	(1,211)	(1,803)	(932)
Amortization of net loss (gain)	915	(5)	(790)
Net periodic postretirement benefit costs under SFAS 106	47,731	40,913	59,903
Additional cost recognized due to effects of regulation	6,641	4,029	5,673
Net cost recognized for financial reporting	$54,372	$44,942	$65,576

11. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Xcel Energy's nonregulated subsidiaries have investments in various international and domestic energy projects, and domestic affordable housing and real estate projects. We use the equity method of accounting for such investments in affiliates, which include joint ventures and partnerships. That's because the ownership structure prevents Xcel Energy from exercising a controlling influence over the projects' operating and financial policies. Under this method, Xcel Energy records its portion of the earnings or losses of unconsolidated affiliates as equity earnings. A summary of Xcel Energy's significant equity method investments is listed in the following table.

Name	*Geographic Area*	*Economic Interest*
Loy Yang Power A	Australia	25.37%
Enfield Energy Centre	Europe	25.00%
Yorkshire Power	Europe	50.00%
Gladstone Power Station	Australia	37.50%
COBEE (Bolivian Power Co. Ltd.)	South America	49.10%
MIBRAG mbH	Europe	33.33%
Cogeneration Corp. of America	USA	20.00%
Schkopau Power Station	Europe	20.95%
Long Beach Generating	USA	50.00%
El Segundo Generating	USA	50.00%
Encina	USA	50.00%
San Diego Combustion Turbines	USA	50.00%
Energy Developments Limited	Australia	29.14%
Scudder Latin American Power	Latin America	6.63%
Various independent power production facilities	USA	45–50%
Various affordable housing limited partnerships	USA	20–99.9%

The following table summarizes financial information for these projects, including interests owned by Xcel Energy and other parties for the years ended Dec. 31.

RESULTS OF OPERATIONS

(Millions of dollars)	2000	1999	1998
Operating revenues	$4,664	$4,087	$3,791
Operating income	$ 464	$ 516	$ 530
Net income (losses)	$ 447	$ 290	$ 220
Xcel Energy's equity earnings of unconsolidated affiliates	$ 184	$ 113	$ 119

FINANCIAL POSITION

(Millions of dollars)	2000	1999
Current assets	$ 1,590	$ 1,198
Other assets	10,939	10,877
Total assets	$12,529	$12,075
Current liabilities	$ 1,833	$ 1,384
Other liabilities	6,806	7,719
Equity	3,890	2,972
Total liabilities and equity	$12,529	$12,075

Subsequent Event

In late February 2001, Xcel Energy reached an agreement in principle to sell at book value all of its investment in Yorkshire Power except for an interest of approximately 5 percent. Xcel Energy is retaining this interest to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Following completion of the transaction, proceeds of the sale will be used by Xcel Energy to pay down short-term debt and eliminate an equity issuance planned for the second half of 2001.

12. ELECTRIC UTILITY RESTRUCTURING

Restructuring legislation has been enacted in Texas and New Mexico, as summarized below. SPS has made, and continues to make, filings with the PUCT and the New Mexico Public Regulation Commission (NMPRC) to address critical issues related to SPS transition plans to implement retail competition.

New Mexico Restructuring In April 1999, New Mexico enacted the Electric Utility Restructuring Act of 1999, which provides for customer choice. The legislation provides for recovery of no less than 50 percent of stranded costs for all utilities. Transition costs must be approved by the NMPRC prior to being recovered through a non-bypassable wires charge, which must be included in transition plan filings. SPS must separate its utility operations into at least two entities: energy generation and competitive services, and transmission and distribution utility services, either by the creation of separate affiliates that may be owned by a common holding company or by the sale of assets to one or more third parties. A regulated company, in general, is prohibited from providing unregulated services. In May 2000, the NMPRC approved:

- Customer choice for residential, small commercial and educational customers by January 2002;
- Customer choice for commercial and industrial customers by July 2002; and
- Completion of SPS corporate separation by August 2001.

The NMPRC has reopened its electric restructuring rulemakings to consider the impacts on New Mexico electricity markets arising from the volatile California electricity market conditions. In addition, in February 2001, the New Mexico Senate approved a bill that would delay the implementation of restructuring and retail choice until 2007. The House has yet to act on the proposal to delay. We cannot predict the changes that may result from reconsideration of the restructuring legislation or the NMPRC's reconsideration of its regulations as a result of the continuing and significant conditions in the California markets.

Texas Restructuring In June 1999, an electric utility restructuring act (SB-7) was passed in Texas, which provides for the implementation of retail competition for most areas of the state, including SPS' service area, beginning January 2002. The PUCT can delay the date for full retail competition if a power region is unable to offer fair competition and reliable service during the 2001 pilot projects. The legislation requires:

- A rate freeze for all customers until January 2002;
- An annual earnings test through 2001;
- A 6-percent rate reduction for those residential and small commercial customers who choose not to switch suppliers at the start of retail competition;
- The unbundling of business activities, costs and rates relating to generation, transmission and distribution, and retail services;
- Reductions in NO_x and SO_2 emissions; and
- The recovery of stranded costs.

SB-7 requires each utility to unbundle its business activities into three separate legal entities: a power generation company, a regulated transmission and distribution company, and a retail electric provider. SB-7 limits the market share that a single generation provider can control to 20 percent of the generating capacity within a qualified power region. The establishment of a qualified power region with multiple generation suppliers is required under SB-7 in order to implement full retail competition. SPS must return any excess earnings above its last allowed rate of return for 1999, 2000 and 2001, or alternatively may direct any excess earnings to improvements in transmission and distribution facilities, to capital expenditures to improve air quality or to accelerate the amortization of regulatory assets, subject to PUCT approval.

The Texas legislature is currently considering amendments to SB-7 that would delay the implementation of business separation and customer choice in SPS' market area for 5 years.

Implementation SPS filed its business separation plan in Texas during the first quarter of 2000 for the unbundling of power generation, transmission, and distribution and retail electric provider services. In April 2000, the PUCT approved SPS' business separation plan. The plan provides for the separation of all competitive energy services, the establishment of an Xcel Energy customer care company, which will provide customer services for all of Xcel Energy's operating utilities, and a formal code of conduct and compliance manual for managing affiliate transactions.

Subject to all required approvals and indebtedness restrictions, it is anticipated that all generation-related and certain other assets and liabilities will be transferred at net book value to newly formed affiliates in accordance with SPS' business separation plan. It is expected that SPS and its affiliates will be capitalized consistent with their respective business operations.

In April 2000, SPS filed with the PUCT a stipulation agreement that specifically addresses SPS' implementation plans to meet the requirements of the Texas restructuring legislation. The stipulation provides for the implementation of full retail customer choice by SPS in its Texas service region, including the future divestiture of certain SPS generation assets. Subject to certain market conditions and confirmation by the SEC that the sale would not violate pooling accounting treatment, SPS agreed to divest at least 1,750 megawatts by January 2002, and specifically identified the plants that it would sell in connection with additional divestitures required to establish a qualified power region under SB-7. In subsequent discussions, the SEC has indicated that the sale of generation assets prior to August 2002 would violate pooling accounting. For SPS to comply with this qualified power region requirement and to implement full customer choice in Texas, between 2,843 megawatts and 3,184 megawatts of existing power generation assets or capacity must be sold to third-party non-affiliates. SPS has committed to complete these divestitures by January 2006. In May 2000, the PUCT issued an order approving the stipulation. SPS has committed to transfer functional control of its electric transmission system to a regional transmission organization that will operate the transmission systems of multiple owners in the central United States.

SPS filed a rate case in March 2000 to set the rates for distribution services in Texas, which are to be unbundled and implemented in January 2002. SPS requested recovery of all jurisdictional costs associated with restructuring in Texas. Hearings and a final rate order are not expected before August 2001.

In June 2000, SPS filed its transition plan with the NMPRC. SPS filed to establish rates for the transmission and distribution business in New Mexico, requesting approval of its corporate restructuring/separation and other associated matters. Hearings were held in October and November 2000. Final approval is not expected until mid-2001.

Financial Impact With the issuance of a final written order by the PUCT in May 2000, addressing the implementation of electric utility restructuring, SPS discontinued regulatory accounting under SFAS 71 for the generation portion of its business during the second quarter of 2000. Consistent with current accounting rules, this resulted in extraordinary charges in the second and third quarters of 2000. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and liabilities, totaling approximately $19.3 million before taxes. This resulted in an after-tax extraordinary charge of approximately $13.7 million against the earnings of Xcel Energy and SPS. During the third quarter of 2000, SPS recorded an extraordinary charge of $8.2 million before tax, or $5.3 million after tax, related to the tender offer and defeasance of approximately $295 million of first mortgage bonds. The first mortgage bonds were defeased to facilitate SPS' eventual divesture of generation assets.

SPS transmission and distribution business continues to meet the requirements of SFAS 71, as that business is expected to remain regulated.

Additionally, there may be other significant financial implications of implementing SB-7 and electric restructuring in New Mexico. These implications include, but are not limited to, investments in information technology, establishing an independent operation of the electric transmission systems, implementing the procedures to govern affiliate transactions, the pricing of unbundled energy services and the regulatory recovery of incurred costs related to these issues. These costs could be as much as $75 million. The total impacts of restructuring are unknown at this time and may have a significant financial impact on the financial position, results of operations and cash flows of Xcel Energy and SPS.

13. FINANCIAL INSTRUMENTS

Fair Values

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

	2000		1999	
(Thousands of dollars)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Mandatorily redeemable preferred securities	$ 494,000	$ 481,270	$ 494,000	$ 427,240
Long-term investments	$ 625,616	$ 624,989	$ 543,300	$ 538,926
Long-term debt, including current portion	$8,187,052	$8,131,139	$6,258,534	$5,997,522

For cash, cash equivalents and short-term investments, the carrying amount approximates fair value because of the short maturity of those instruments. The fair values of Xcel Energy's long-term investments, mainly debt securities in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair value of Xcel Energy's long-term debt and the mandatorily redeemable preferred securities are estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair-value estimates presented are based on information available to management as of Dec. 31, 2000 and 1999. These fair-value estimates have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

Xcel Energy has entered into a construction contract guarantee that assures Quixx's performance under its engineering, procurement and construction contract with Borger Energy Associates, LP (BEA). Quixx, which owns 45 percent of BEA, is constructing a 230-megawatt cogeneration facility at a Phillips Petroleum site near Borger, Texas. The maximum aggregate amount of this guarantee at Dec. 31, 2000, was $88.4 million. This maximum amount decreases to $25 million at commercial operation of the facility and remains in effect for a period of no longer than 24 months before expiring.

In July 1999, Xcel Energy entered into a guarantee resulting from non-completion of certain milestone achievements within required dates in connection with the Quixx Linden cogeneration plant. The guarantee, totaling approximately $7.5 million, is for the benefit of Bank One and all other lenders in Quixx Linden, LP. Once the milestone events are accomplished, the guarantee is required to remain for six months.

As of Dec. 31, 2000, Xcel Energy had outstanding approximately $190 million of guarantees relating to e prime. These guarantees were made to facilitate e prime's natural gas marketing and trading activities.

As of Dec. 31, 2000, Xcel Energy provided guarantees for EMI of approximately $27 million. Approximately $12 million of these guarantees related to energy conservation projects in which EMI has guaranteed certain energy savings to the customer. As energy savings are realized each year due to these projects, the value of the guarantee decreases until it reaches zero in 2017. Approximately $15 million of the guarantees relates to EMI's line of credit with US Bank.

The Bank of New York has provided a letter of credit, at the request of Xcel Energy, of approximately $1.0 million to fulfill debt service reserve requirements as support for a Young Gas Storage Co., Ltd. loan. Young Gas Storage entered into a $30.7-million credit agreement with various lending institutions in March 1999 with a maturity of March 2014. The loan was incurred for the development and construction of an underground natural gas storage facility in northeastern Colorado. Separately, Xcel Energy has guaranteed up to $4.5 million to cover costs of expenses related to the project.

NSP-Minnesota has sold a portion of its other receivables to a third party. The portion of the receivables sold consisted of customer loans to local and state government entities for energy efficiency improvements under various conservation programs offered by NSP-Minnesota. Under the sales agreements, NSP-Minnesota is required to guarantee repayment to the third party of the remaining loan balances. At Dec. 31, 2000, the outstanding balance of the loans was approximately $18.1 million. Based on prior collection experience of these loans, NSP-Minnesota believes that losses under the loan guarantees, if any, would have an immaterial impact on the results of operations.

In connection with an agreement for the sale of electric power, SPS guaranteed certain obligations of a customer totaling approximately $27.8 million at Dec. 31, 2000. These obligations related to the construction of certain utility property that, in the event of default by the customer, would revert to SPS.

In June 2000, Xcel Energy entered into a guarantee on behalf of BNP Paribas in connection with a letter of credit provided by BNP Paribas at the request of SPS in the amount of $5 million, expiring March 2002. The letter of credit is required to indemnify former SPS board of directors.

Derivatives

As of Dec. 31, 2000, NRG had four interest rate swap agreements with notional amounts totaling approximately $533 million. If the swaps had been discontinued on Dec. 31, 2000, NRG would have owed the counterparties approximately $31 million. NRG believes that its exposure to credit risk due to nonperformance by the counterparties to the hedging contracts is insignificant. These swaps are described below.

- A swap effectively converts a $16-million issue of non-recourse variable rate debt into fixed-rate debt. The swap expires in September 2002 and is secured by the Camas Power Boiler assets.
- A swap converts $178 million of non-recourse variable rate debt into fixed-rate debt. The swap expires in December 2014 and is secured by the Crockett Cogeneration assets.
- A swap converts £188 million, the equivalent of $281 million, of non-recourse variable rate debt into fixed-rate debt. The swap expires in June 2019 and is secured by the Killingholme assets.
- A swap converts variable rate debt to fixed rate debt. The notional amount is AUD 105 million, the equivalent of $59 million as of Dec. 31, 2000. The swap expires in September 2012 and is secured by the Flinders Power assets.

SPS has an interest rate swap with a notional amount of $25 million, converting variable rate debt to a fixed-rate. Young Gas Storage and Quixx Linden projects, which are unconsolidated equity investments of Xcel Energy, have interest rate swaps converting project debt from variable rate to fixed rate. These two amortizing swaps had a total notional amount of $39.5 million on Dec. 31, 2000. The approximate termination cost of Xcel Energy's portion of these three swaps was $4.5 million at Dec. 31, 2000.

Xcel Energy's regulated energy marketing operation uses a combination of energy futures and forward contracts, along with physical supply to hedge market risks in the energy market. At Dec. 31, 2000, the notional value of these contracts was approximately $90.4 million. If these contracts had been terminated on Dec. 31, 2000, Xcel Energy would have realized a net gain of approximately $18.7 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

NRG's Power Marketing subsidiary uses energy futures and forward contracts, along with physical supply, to hedge market risk in the energy market. At Dec. 31, 2000, the net notional amount of these contracts was approximately $309.3 million. If the contracts had been terminated on Dec. 31, 2000, NRG would have received approximately $52.8 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

e prime uses various financial instruments as hedging mechanisms against future energy-related contractual obligations. e prime had financial derivatives related to its retail business with a notional value of $8.3 million at Dec. 31, 2000. If these contracts had been terminated at Dec. 31, 2000, e prime would have realized a net gain of $3.9 million. In addition, e prime's wholesale portfolio had a net notional value of ($0.5) million, based on a combination of physical and financial transactions. If these contracts had been terminated on Dec. 31, 2000, e prime would have received $3.3 million from the counterparties. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

NRG had one foreign currency hedge outstanding at Dec. 31, 2000. The contract had a notional value of $8.8 million and hedged expected cash flows from the Killingholme project in England. The currency hedge expired on Jan. 31, 2001. If the contract had been terminated on Dec. 31, 2000, NRG would have paid the counterparties $0.7 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. In addition, NRG uses letters of credit for nonregulated equity commitments, collateral for credit agreements, fuel purchase and operating commitments, and bids on development projects. At Dec. 31, 2000, there were $113 million in letters of credit outstanding, including $58 million related to NRG commitments. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

14. COMMITMENTS AND CONTINGENT LIABILITIES

Legislative Resource Commitments

In 1994, NSP-Minnesota received Minnesota legislative approval for additional on-site temporary spent fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Seventeen dry cask containers were approved. As of Dec. 31, 2000, NSP-Minnesota had loaded twelve casks. The Minnesota Legislature established several energy resource and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. These commitments can be met by building, purchasing, or in the case of biomass, converting generation resources.

The 1994 legislation requires NSP-Minnesota to have 425 megawatts of wind resources contracted by Dec. 31, 2002. Of this commitment, approximately 80 megawatts remain to be contracted. During 1999, the MPUC ordered an additional 400 megawatts to be contracted by 2012, subject to least-cost determinations. The 1994 legislation also requires NSP-Minnesota to contract for 125 megawatts of biomass-fueled energy, which has essentially been fulfilled.

Other commitments established by the Legislature include a discount for low-income electric customers, required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force. NSP-Minnesota has implemented programs to meet the legislative commitments. NSP-Minnesota's capital commitments include the known effects of the Prairie Island legislation. The impact of the legislation on future power purchase commitments and other operating expenses is not yet determinable.

Capital Commitments

As discussed in Liquidity and Capital under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2000, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately $5.0 billion in 2001, $3.0 billion in 2002 and $3.3 billion in 2003.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission control equipment may impact actual capital requirements.

Xcel Energy's capital expenditures include approximately $3.1 billion in 2001 for NRG investments and asset acquisitions. NRG's future capital requirements may vary significantly. For 2001, NRG's capital requirements reflect expected acquisitions of existing generation facilities, including the Conectiv fossil assets, North Valmy, LS Power, Clark gas-fired assets, Reid Gardner coal-fired assets and the Bridgeport and New Haven Harbor coal-fired facilities.

California Power Market

NRG operates in and sells to the wholesale power market in California. During the fourth quarter of 2000, the inability of certain California utilities to recover rising energy costs through regulated prices charged to retail customers created financial difficulties. The California utilities have appealed to state agencies and regulators for the opportunity to be reimbursed for costs incurred that are not currently recoverable through the existing rate structure. Absent such relief, some of the utilities have indicated they may be unable to continue to service their debt and/or otherwise pay obligations, or would consider discontinuing energy service to customers to avoid incurring costs that are not recoverable. Due to these circumstances, various bond rating agencies have lowered the credit rating of the California utilities to below investment grade. California state agencies and regulators, along with federal agencies such as the FERC have characterized the situation as a national emergency. Although changes may be necessary in the California utility regulatory model to address the problem in the long run, in the short term the alternatives being discussed include financial support for distressed utilities to ensure continued energy service to California customers. However, at this time it is unknown whether or when such financial support will be made available to California utilities.

At Dec. 31, 2000, NRG had not yet collected approximately $105 million in revenues from distressed utilities and the independent system operator in California, which are potentially at risk if financial relief or support is not provided. In addition, Xcel Energy's wholesale trading operation has a receivable from the California Independent System Operator for approximately $3 million. Although there is uncertainty as to the final resolution of this matter, management believes that its revenue from California utilities and the independent system operator will ultimately be collected.

Tax Matters

PSR Investments, Inc. (PSRI), a subsidiary of PSCo, owns and manages permanent life insurance policies on certain past and present employees. The IRS has issued a Notice of Proposed Adjustment proposing to disallow interest expense related to corporate-owned life insurance (COLI) policy loans taken in tax years 1993–1997. The total disallowance of interest expense deductions for the five years as proposed by the IRS is approximately $175 million. A request for technical advice from the IRS National Office with respect to the proposed adjustment is pending. In addition, interest expense deductions for the period 1998 through 2000 totals approximately $168 million.

Management is vigorously contesting this issue. While the outcome of this matter cannot be predicted, management believes that PSRI's tax deduction of interest expense on life insurance policy loans was in full compliance with the tax law and believes that the resolution of this matter will not have a material adverse impact on Xcel Energy's financial position, results of operations or cash flows. For this reason, PSRI has not recorded any provision for income tax or interest expense related to this matter and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years.

Postemployment Benefits

PSCo adopted accrual accounting for postemployment benefits under SFAS No. 112 – "Employers' Accounting for Postemployment Benefits" in 1994. The costs of these benefits were historically recorded on a pay-as-you-go basis and, accordingly, PSCo recorded regulatory assets in anticipation of obtaining future rate recovery of these costs. PSCo recovered its FERC jurisdictional portion of these costs. PSCo requested approval to recover its Colorado retail natural gas jurisdictional portion in a 1996 retail rate case and its retail electric jurisdictional portion in the electric earnings test filing for 1997. In the 1996 rate case, the CPUC allowed recovery of postemployment benefit costs on an accrual basis, but denied PSCo's request to amortize the regulatory asset. PSCo appealed this decision to the Denver District Court. In 1998, the CPUC deferred the final determination of the regulatory treatment of the electric jurisdictional costs pending the outcome of PSCo's appeals on the natural gas rate case. On Dec. 16, 1999, the Denver District Court affirmed the decision by the CPUC. On Jan. 31, 2000, PSCo filed a Notice of Appeal with the Colorado Supreme Court and expects a final decision on this matter during 2001. PSCo continues to believe that it will ultimately be allowed to recover this regulatory asset. If PSCo is unsuccessful in its appeal, all unrecoverable amounts totaling approximately $23 million will be written off.

Conservation Incentive Recovery

In June 1999, the MPUC denied NSP-Minnesota recovery of 1998 lost margins, load management discounts and incentives associated with state-mandated programs for electric energy conservation. Xcel Energy recorded a $35 million charge in 1999 based on this action. NSP-Minnesota appealed the MPUC decision and in December 2000, the Minnesota Court of Appeals reversed the MPUC decision.

In January 2001, the MPUC appealed the lower court decision to the Minnesota Supreme Court. On Feb. 23, 2001, the Minnesota Supreme Court declined to hear the MPUC's appeal. NSP-Minnesota is awaiting an order from the MPUC regarding the implementation of the appeals court decision before adjusting any liabilities recorded for this matter. As of Dec. 31, 2000, NSP-Minnesota had recorded a liability of $40 million, including carrying charges, for potential refunds to customers pending the final resolution of this matter.

Leases

Xcel Energy's subsidiaries lease various equipment and facilities used in the normal course of business, some of which are accounted for as capital leases. Expiration of the capital leases range from 2010 to 2029. The net book value of property under capital leases was approximately $55 million and $57 million at Dec. 31, 2000 and 1999, respectively. Assets acquired under capital leases are recorded as property at the lower of fair-market value or the present value of future lease payments and are amortized over their actual contract term in accordance with practices allowed by regulators. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

Rental expense under operating lease obligations was approximately $56 million, $57 million and $49 million for 2000, 1999 and 1998, respectively. Future commitments under these leases generally decline from current levels.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $9.5 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $9.3 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $88 million for each of its three licensed reactors to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $1.5 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $3 million for business interruption insurance and $11 million for property damage insurance if losses exceed accumulated reserve funds.

Fuel Contracts

Xcel Energy has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2001 and 2017. In total, Xcel Energy is committed to the minimum purchase of approximately $2.1 billion of coal, $13 million of nuclear fuel and $706 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy's risk of loss, in the form of increased costs, from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of most fuel costs.

Purchase Power Agreements

The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost recovery mechanisms. Additionally, NSP-Minnesota, PSCo and SPS have long-term, purchased-power contracts with various regional utilities, expiring through 2025.

NSP-Minnesota has a 500-megawatt participation power purchase commitment with Manitoba Hydro, which expires in 2005. The cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota's Sherco 3 generating plant, adjusted to 1993 dollars. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro's system capacity and account for approximately 10 percent of NSP-Minnesota's 2000 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2000, the estimated future payments for capacity that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Thousands of dollars)	*Other*	*Regional Utilities*	*Total*
2001	$ 203,347	$ 253,932	$ 457,279
2002	225,031	241,358	466,389
2003	256,791	231,361	488,152
2004	255,185	221,907	477,092
2005 and thereafter	2,061,785	983,144	3,044,929
Total	$3,002,139	$1,931,702	$4,933,841

For the past 37 years, Cheyenne has purchased all energy requirements from PacifiCorp. Cheyenne's full-requirements power purchase agreement with PacifiCorp expired in December 2000. During 2000, Cheyenne issued a request for proposal and conducted negotiations with PacifiCorp and other wholesale power suppliers. During 2000, as contract details for a new agreement were being finalized, supply conditions and market prices in the western United States dramatically changed. Cheyenne was unable to execute an agreement with PacifiCorp for the prices and terms Cheyenne had been negotiating. Additionally, PacifiCorp failed to provide the FERC and Cheyenne 60-days notice to terminate service, as required by the Federal Power Act. Cheyenne filed a complaint with the FERC, requesting that PacifiCorp continue providing service under the existing tariff through the 60-day notice period. On Feb. 7, 2001, the FERC issued an order requiring PacifiCorp to provide service under the terms of the old contract through Feb. 24, 2001.

Cheyenne has begun implementing the changes required to transition from a full-requirements customer to an operating utility as the best means of providing energy supply. In February 2001, PSCo filed an agreement with the FERC to provide a portion of Cheyenne's service. Cheyenne has also entered into agreements with other producers to meet both short-term and long-term energy supply needs and continues to negotiate with suppliers to meet its load requirements for the summer of 2001.

Total purchased power costs are projected to increase approximately $80 million in 2001. Purchased power and natural gas costs are recoverable in Wyoming. Cheyenne is required to file applications with the WPSC for approval of adjustment mechanisms in advance of the proposed effective date and demonstrate the reasonableness of the costs. Cheyenne expects to make its request for an electric cost adjustment increase in March 2001.

Environmental Contingencies

We are subject to regulations covering air and water quality, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the construction and operation of, and cost of building and operating, our facilities.

Site Remediation

We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2000, there were three categories of sites:

- Third-party sites, such as landfills, to which we are alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes;
- The site of a former federal uranium enrichment facility; and
- Sites of former manufactured gas plants (MGPs) operated by our subsidiaries or predecessors.

We record a liability when we have enough information to develop an estimate of the cost of remediating a site and revise the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, we may have to make assumptions where facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties and the identification of new environmental cleanup sites.

We revise our estimates as facts become known, but at Dec. 31, 2000, our liability for the cost of remediating sites for which an estimate was possible was $54 million, including $14 million in current liabilities.

Some of the cost of remediation may be recovered from others through:

- Insurance coverage;
- Recovery from other parties that have contributed to the contamination; and
- Recovery from customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. We have recorded estimates of our share of future costs for these sites. We are not aware of any other parties' inability to pay, nor do we know if responsibility for any of the sites is in dispute.

Federal Uranium Enrichment Facility

Approximately $23 million of the long-term liability and $4 million of the current liability relate to a DOE assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. These environmental liabilities do not include accruals recorded and collected from customers in rates for future nuclear fuel disposal costs or decommissioning costs related to NSP-Minnesota's nuclear generating plants. See Note 15 to Financial Statements for further discussion of nuclear obligations.

MGP Sites

NSP-Wisconsin was named as one of three PRPs for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city, lakeshore park area and a small area of Lake Superior's Chequemegon Bay adjoining the park.

The Wisconsin Department of Natural Resources (WDNR) and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR are expected to select the method of remediation to use at the site during late 2001 or early 2002. Until the EPA and the WDNR select a remediation strategy for all operable units at the site and determine the level of responsibility of each PRP, we are not able to accurately estimate our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, estimated using information available to date and using reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for 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.

We proposed, and the EPA and WDNR have approved, an interim action (a groundwater treatment system) for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to ultimate remediation cost of the entire site. It is probable that, even with outside funding, final remedial costs to be borne by NSP-Wisconsin will be material.

The MPUC allowed NSP-Minnesota to defer certain remediation costs of four active remediation sites in 1994. In September 1998, the MPUC allowed the recovery of these MGP site remediation costs in natural gas rates, with a portion assigned to NSP's electric operations for two sites formerly used by NSP generating facilities. Accordingly, NSP-Minnesota has recorded an environmental regulatory asset for these costs. NSP-Minnesota may request recovery of costs to remediate other activated sites following the completion of preliminary investigations.

Other

Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. 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.

In January 1996, in a lawsuit by PSCo against its insurance providers, the Denver District Court entered final judgment in favor of PSCo in the amount of $5.6 million for certain cleanup costs at the Barter site in central Denver. In September 1999, the Colorado Supreme Court held that the trial court should have allocated the damages and self-insured retentions over the entire period the facilities were in operation. Although the Colorado Supreme Court remanded the judgement to the trial court for additional proceedings, it suggested that its ruling may reduce PSCo's available recovery to approximately $1.4 million. PSCo requested recovery of environmental costs of approximately $7.7 million related to Barter over four years in its proposed Performance-Based Regulatory Plan for calendar years 1998–2001.

Plant Emissions

In 1996, a conservation organization filed a complaint in the U.S. District Court pursuant to provisions of the Clean Air Act against the joint owners of the Craig Steam Electric Generating Station, located in western Colorado. Tri-State Generation and Transmission Association, Inc. is the operator of the Craig station and PSCo owns an undivided interest in each of two units at the station, totaling approximately 9.7 percent. In October 2000, the parties, the EPA and the Colorado Department of Public Health and Environment (CDPHE) reached an agreement in principle resolving all air-quality matters related to the facility. The final agreement was negotiated during the fourth quarter of 2000 and was filed with the court on Jan. 10, 2001. The final agreement requires the installation of additional emission control equipment at a cost of approximately $105 million (based on an estimate from Tri-State). The equipment will be installed over a period of several years. In addition, the settlement requires the defendants collectively to pay a civil penalty of $500,000 and to contribute $1.5 million to fund conservation activities. The contribution to conservation activities will be refunded if the plant achieves a specified level of emissions control. The agreement will become enforceable after a period for public comment and approval by the court.

In October 2000, the EPA found that NSP-Wisconsin's French Island electric generating plant should be classified as a "large municipal waste combustor" under Section 129 of the Clean Air Act. This letter was contrary to a 1997 EPA letter in which it had found that French Island should be classified as a "small combustor." The large combustor emission limits became enforceable in December 2000. NSP-Wisconsin is attempting to work with the EPA to resolve the dispute regarding the status of the French Island plant. If a resolution is finalized, it may require, among other things, the installation of additional emission controls on the plant.

NRG also owns electric generating plants throughout the United States. These plants are subject to federal and state emission standards and other environmental regulations. NRG continues to study and investigate the methods and costs of complying with these standards and regulations. Although the future financial effect is not yet known, it may be material.

The Commonwealth of Massachusetts is seeking additional emissions reductions beyond current requirements. The Massachusetts Department of Environmental Protection (MDEP) has issued proposed regulations that would require significant emissions reductions from certain coal-fired power plants in the state, including NRG's Somerset facility. The MDEP has proposed that such facilities comply with stringent limits on emissions of NO_x by December 2003; on emissions of SO_2 commencing in December 2003, with further reductions required by December 2005; and on emissions of CO_2 by December 2005. In addition to output-based limits (a standard which limits emissions to a certain rate per net megawatt-hour), the proposed regulations also would limit, by December 2003, the total emissions of nitrogen oxides and sulfur dioxide at the Somerset facility to no more than 75 percent of the average annual emissions of the Somerset facility for the years 1997 through 1999. Finally, the proposed regulations require the MDEP to evaluate, by December 2002, the technological and economic feasibility of controlling or eliminating mercury emissions by the year 2010, and to propose mercury emission standards within 18 months of completion of the feasibility evaluation. Compliance with these proposed regulations, if such regulations become effective, could have a material impact on the operation of NRG's Somerset facility. The annual average carbon dioxide emission rate identified in the proposed regulations cannot be met by the Somerset facility.

Legal Claims

In the normal course of business, Xcel Energy is a party to routine claims and litigation arising from prior and current operations. Xcel Energy is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition.

On Dec. 11, 1998, a natural gas explosion in St. Cloud, Minn., killed four people, including two NSP-Minnesota employees, injured approximately 14 people and damaged several buildings. The accident occurred as a crew from Cable Constructors Inc. (CCI) was installing fiber optic cable for Seren. Seren, CCI and Sirti, an architecture/engineering firm retained by Seren, are named as defendants in 22 lawsuits relating to the explosion. NSP-Minnesota is a defendant in 19 of the lawsuits. NSP-Minnesota and Seren deny any liability for this accident. On July 11, 2000, the National Transportation Safety Board issued a report, which determined that CCI's inadequate installation procedures and delay in reporting the natural gas hit were the proximate cause of the accident. NSP-Minnesota has a self-insured retention deductible of $2 million with general liability coverage limits of $185 million. Seren's primary insurance coverage is $1 million and its secondary insurance coverage is $185 million. The ultimate cost to Xcel Energy, NSP-Minnesota and Seren, if any, is presently unknown.

On or about July 12, 1999, Fortistar Capital, Inc. commenced an action against NRG in Hennepin County (Minnesota) District Court, seeking damages in excess of $100 million and an order restraining NRG from consummating the acquisition of Niagara Mohawk Power Corp.'s Oswego generating station. Fortistar's motion for a temporary restraining order was denied. A temporary injunction hearing was held on Sept. 27, 1999. The acquisition was consummated in October 1999. On Jan. 14, 2000, the court denied Fortistar's request for a temporary injunction. In April and December 2000, NRG filed summary judgment motions to dispose of the litigation respecting both liability and damages, and a hearing on these motions was held on Jan. 26, 2001. No ruling on the motions has been received to date. A trial date has been scheduled for April 2001. NRG has asserted numerous counterclaims against Fortistar and will continue to vigorously defend the suit.

NRG and other power generators and power traders have been named as defendants in certain private plaintiff class actions filed in the Superior Court of the State of California for the County of San Diego in San Diego, California, on Nov. 27, 2000, and Nov. 29, 2000, and in the Superior Court of the State of California, City and County of San Francisco filed Jan. 24, 2001. NRG and other power generators and power traders have also been named in another suit filed on Jan. 16, 2001, in the Superior Court of the State of California for the County of San Diego, brought by three California water districts, as consumers of electricity and in a suit filed on Jan. 18, 2001, in Superior Court of the State of California, County of San Francisco, brought by the San Francisco City Attorney on behalf of the People of the State of California. Xcel Energy and Northern States Power Company were also named as defendants in the litigation commenced in San Francisco because of their relationship with NRG. Although the complaints contain a number of allegations, the basic claim is that, by underbidding forward contracts and exporting electricity to surrounding markets, the defendants, acting in collusion, were able to drive up wholesale prices on the Real Time and Replacement Reserve markets, through the Western Systems Coordinating Council and otherwise. The complaints allege that the conduct violated California antitrust and unfair competition laws. NRG does not believe that it has engaged in any illegal activities and intends to vigorously defend these lawsuits.

On Feb. 3, 2000, Dynegy Engineering Inc. filed a lawsuit against Utility Engineering (UE), a wholly owned subsidiary of Xcel Energy, in Harris County, Texas. In its lawsuit, Dynegy claims it is entitled to recover approximately $9.7 million for damages allegedly caused by UE's late and deficient engineering services performed for the Rocky Road electrical generating plant in Dundee, Ill. UE denies the merits of Dynegy's lawsuit. UE also maintains that it is insured against this claim pursuant to its professional liability policy. UE's self-insured retention under this policy is $1 million.

15. NUCLEAR OBLIGATIONS

Fuel Disposal

NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP's nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately $12 million in 2000, $12 million in 1999 and $11 million in 1998. In total, NSP-Minnesota had paid approximately $284 million to the DOE through Dec. 31, 2000. However, we cannot determine whether the amount and method of the DOE's assessments to all utilities will be sufficient to fully fund the DOE's permanent storage or disposal facility.

The Nuclear Waste Policy Act required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. In 1996, the DOE notified commercial spent fuel owners of an anticipated delay in accepting spent nuclear fuel by the required date and conceded that a permanent storage or disposal facility will not be available until at least 2010. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE's failure to meet its statutory and contractual obligations.

NSP-Minnesota has its own temporary on-site storage facilities at its Monticello and Prairie Island nuclear plants. With the dry cask storage facilities approved in 1994, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least 2007. The Monticello nuclear plant has storage capacity to continue operations until 2010. Storage availability to permit operation beyond these dates is not assured at this time. We are investigating alternatives for spent fuel storage until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities. If on-site temporary storage at Prairie Island reaches approved capacity, we could seek interim storage at this or another contracted private facility, if available.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE's uranium enrichment facilities. In 1993, NSP-Minnesota recorded the DOE's initial assessment of $46 million, which is payable in annual installments from 1993–2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2000 was $4 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, we deferred the unamortized assessment of $28 million at Dec. 31, 2000, as a regulatory asset.

Plant Decommissioning

Decommissioning of NSP-Minnesota's nuclear facilities is planned for the years 2010–2022, using the prompt dismantlement method. We are currently following industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in Utility Plant – Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy's financial statements.

The FASB has proposed new accounting standards that, if approved, would require the full accrual of nuclear plant decommissioning and other site exit obligations no sooner than 2002. Using Dec. 31, 2000, estimates, adoption of the proposed accounting would result in the recording of the total discounted decommissioning obligation of $838 million as a liability, with the corresponding costs capitalized as plant and other assets and depreciated over the operating life of the plant. We have not yet determined the potential impact of the FASB's proposed changes in the accounting for site exit obligations, such as costs of removal, other than nuclear decommissioning. However, the ultimate decommissioning and site exit costs to be accrued are expected to be similar to the current methodology. The effects of regulation are expected to minimize or eliminate any impact on operating expenses and results of operations from this future accounting change.

Consistent with cost recovery in utility customer rates, we record annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Funding presumes that current costs will escalate in the future at a rate of 4.5 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding.

The MPUC last approved NSP-Minnesota's nuclear decommissioning study and related nuclear plant depreciation capital recovery request in April 2000, using 1999 cost data. Although we expect to operate Prairie Island through the end of each unit's licensed life, the approved capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2007. This is about seven years earlier than each unit's licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding used fuel storage. We believe future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2000, primarily consisted of investments in fixed-income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in 1 to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

At Dec. 31, 2000, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $583 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation at Dec. 31, 2000:

(Thousands of dollars)	2000
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	$ 958,266
Effect of escalating costs to 2000 dollars (at 4.5 percent per year)	41,685
Estimated decommissioning cost obligation in current dollars	999,951
Effect of escalating costs to payment date (at 4.5 percent per year)	894,322
Estimated future decommissioning costs (undiscounted)	1,894,273
Effect of discounting obligation (using risk-free interest rate)	(1,056,360)
Discounted decommissioning cost obligation	837,913
Assets held in external decommissioning trust	563,812
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 274,101

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	2000	1999	1998
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$51,433	$33,178	$33,178
Internally funded (including interest costs)	(16,111)	1,595	1,477
Interest cost on externally funded decommissioning obligation	5,151	4,191	6,960
Earnings from external trust funds	(5,151)	(4,191)	(6,960)
Net decommissioning accruals recorded	$35,322	$34,773	$34,655

Decommissioning and interest accruals are included with the accumulated provision for depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in other income and deductions on the income statement.

16. REGULATORY ASSETS AND LIABILITIES

Our regulated businesses prepare their financial statements in accordance with the provisions of SFAS 71, as discussed in Note 1 to the Financial Statements. Under SFAS 71, regulatory assets and liabilities can be created for amounts that regulators may allow us to collect, or may require us to pay back to customers in future electric and natural gas rates.

SFAS 71 accounting cannot be used by any portion of our business that is not regulated. Efforts to restructure and deregulate the utility industry have already ended our ability to apply SFAS 71 to the generation business of SPS and may further reduce or end our ability to apply SFAS 71 in the future. Write-offs and material changes to our balance sheet, income and cash flows may result.

Restructuring legislation was enacted in the SPS jurisdictions of Texas and New Mexico. See Note 12 to the Financial Statements. When the final PUCT restructuring order was issued in May 2000, SPS discontinued using SFAS 71 accounting for its electric generation business. In the second quarter of 2000, SPS' generation-related regulatory assets and other deferred costs were written off. SPS' electric transmission and distribution businesses continue to meet the requirements of SFAS 71 and are expected to remain regulated.

The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

(Thousands of dollars)	*Remaining Amortization Period*	**2000**	**1999**
AFDC recorded in plant*	Plant Lives	$159,406	$184,860
Conservation programs*	Up to 5 Years	52,444	40,868
Losses on reacquired debt	Term of Related Debt	85,688	84,190
Environmental costs	Primarily 9 Years	47,595	48,708
Unrecovered gas costs**	1–2 Years	24,719	15,266
Deferred income tax adjustments	Mainly Plant Lives		28,581
Nuclear decommissioning costs	5 Years	54,267	63,835
Employees' postretirement benefits other than pension	12 Years	46,680	53,321
Employees' postemployment benefits	Undetermined	23,223	23,374
Renewable development costs	Undetermined	10,500	
State commission accounting adjustments*	Plant Lives	7,614	7,641
Other	Various	12,125	16,083
Total regulatory assets		$524,261	$566,727
Investment tax credit deferrals		$119,060	$136,349
Unrealized gains from decommissioning investments		171,736	177,578
Pension costs-regulatory differences		139,178	84,198
Conservation incentives		40,679	25,284
Deferred income tax adjustments		12,416	
Fuel costs, refunds and other		11,497	18,795
Total regulatory liabilities		$494,566	$442,204

**Earns a return on investment in the ratemaking process.*

***Excludes current portion with expected rate recovery within 12 months of $13 million and $8 million for 2000 and 1999, respectively. In addition, excludes other deferred energy costs also recoverable within 12 months of $270 million and $47 million for 2000 and 1999, respectively.*

17. CAJUN PRO FORMA RESULTS

During March 2000, NRG completed the acquisition of two fossil-fueled generating plants from Cajun Electric Power Cooperative, Inc., for approximately $1 billion. The following information summarizes the pro forma results of operations as if the acquisition, which was accounted for as a purchase, had occurred as of the beginning of the respective periods for which pro forma information is presented. The preacquisition period information is not necessarily comparable to the postacquisition period information.

	Actual Results	
(Millions of dollars, except earnings per share)	**2000**	**1999**
Revenue	$11,592	$7,816
Net income	527	571
Earnings available for common shareholders	523	566
Total earnings per share	$ 1.54	$ 1.70

	Pro Forma Results (unaudited)	
(Millions of dollars, except earnings per share)	**2000**	**1999**
Revenue	$11,672	$8,184
Net income	523	574
Earnings available for common shareholders	519	569
Total earnings per share	$ 1.54	$ 1.71

18. SEGMENT AND RELATED INFORMATION

Xcel Energy has five reportable segments: Electric Utility, Gas Utility and three of its nonregulated energy businesses, NRG, Xcel International and e prime, all subsidiaries of Xcel Energy.

- Xcel Energy's Electric Utility generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, New Mexico, Wyoming, Kansas and Oklahoma. It also makes sales for resale and provides wholesale transmission service to various entities in the United States. Electric Utility also includes electric trading.
- Xcel Energy's Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan, Arizona, Colorado and Wyoming.
- NRG develops, builds, acquires, owns and operates several nonregulated energy-related businesses, including independent power production, commercial and industrial heating and cooling, and energy-related refuse-derived fuel production, both domestically and outside the United States.
- Xcel Energy International's most significant holding is Yorkshire Power, a joint venture equally owned by Xcel Energy International and a subsidiary of American Electric Power Co. Yorkshire's main business is the distribution and supply of electricity and the supply of natural gas in the United Kingdom.
- e prime trades and markets natural gas throughout the United States.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include a company involved in nonregulated power and natural gas marketing activities throughout the United States; a company that invests in and develops cogeneration and energy-related projects; a company that is engaged in engineering, design construction management and other miscellaneous services; a company engaged in energy consulting, energy efficiency management, conservation programs and mass market services; an affordable housing investment company; a broadband telecommunications company; and several other small companies and businesses.

To report net income for electric and natural gas utility segments, Xcel Energy must assign or allocate all costs and certain other income. In general, costs are:

- Directly assigned wherever applicable;
- Allocated based on cost causation allocators wherever applicable; and
- Allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

Business Segments

(Thousands of dollars)	*Electric Utility*	*Gas Utility*	*NRG*	*Xcel Energy International*	*e prime*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
2000								
Operating revenues from external customers*	$6,492,194	$1,466,478	$2,014,757		$1,269,506	$162,566		$11,405,501
Intersegment revenues	1,179	5,761	2,256		53,928	78,419	$(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates			142,086	$35,327	1,203	4,098		182,714
Total revenues	$6,493,373	$1,472,239	$2,159,099	$35,327	$1,324,637	$245,083	$(137,962)	$11,591,796
Depreciation and amortization	574,018	85,353	123,404	178	569	8,873		792,395
Financing costs, mainly interest expense	333,512	60,755	295,917	7,887	200	57,614	(59,780)	696,105
Income tax expense (credit)	261,942	36,962	92,474	(604)	(3,995)	(81,914)		304,865
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$29,325	$ (6,158)	$ (43,250)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)							(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$29,325	$ (6,158)	$ (43,250)	$ (15,609)	$ 526,828

(Thousands of dollars)	*Electric Utility*	*Gas Utility*	*NRG*	*Xcel Energy International*	*e prime*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
1999								
Operating revenues from external customers*	$5,454,958	$1,141,294	$427,567		$564,045	$114,587		$7,702,451
Intersegment revenues	1,303	11,785	963		2,102	119,546	$(134,731)	968
Equity in earnings (losses) of unconsolidated affiliates			68,947	$ 44,908	1,467	(3,198)		112,124
Total revenues	$5,456,261	$1,153,079	$497,477	$ 44,908	$567,614	$230,935	$(134,731)	$7,815,543
Depreciation and amortization	546,794	82,206	37,026	182	3,762	14,005		683,975
Financing costs, mainly interest expense	300,108	53,217	92,570	714	226	25,262	(19,020)	453,077
Income tax expense (credit)	272,129	24,081	(26,416)	(13,559)	(2,984)	(59,443)	(14,135)	179,673
Segment net income (loss)	$ 431,510	$ 49,175	$ 57,195	$ 58,301	$ (4,765)	$ (7,362)	$ (13,121)	$ 570,933

(Thousands of dollars)	*Electric Utility*	*Gas Utility*	*NRG*	*Xcel Energy International*	*e prime*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
1998								
Operating revenues from external customers*	$5,057,936	$1,109,953	$ 98,688		$181,992	$162,813		$6,611,382
Intersegment revenues	1,131	14,573	1,737			75,209	$(91,722)	928
Equity in earnings (losses) of unconsolidated affiliates			81,706	$ 38,127	1,504	(5,352)		115,985
Total revenues	$5,059,067	$1,124,526	$182,131	$ 38,127	$183,496	$232,670	$(91,722)	$6,728,295
Depreciation and amortization	524,703	75,753	16,320	121	3,438	10,915		631,250
Financing costs, mainly interest expense	262,654	44,074	50,313	745	675	18,960	5,865	383,286
Income tax expense (credit)	300,103	24,945	(25,654)	(15,817)	(1,987)	(26,225)	(14,974)	240,391
Segment net income (loss)	$ 505,077	$ 47,180	$ 41,732	$ 51,978	$ (3,256)	$ 9,621	$(28,002)	$ 624,330

**All operating revenues are from external customers located in the United States except $290 million of NRG operating revenues in 2000, which came from external customers outside of the United States. However, Xcel Energy International and NRG also have significant equity investments for nonregulated projects outside the United States. NRG's equity in earnings of unconsolidated affiliates, primarily independent power projects, includes $19.2 million in 2000, $38.6 million in 1999 and $29.3 million in 1998 from nonregulated projects located outside of the United States. NRG's equity investments in projects outside of the United States were $566 million in 2000, $606 million in 1999 and $557 million in 1998. All of Xcel Energy International's equity in earnings of unconsolidated affiliates is from outside of the United States. Xcel Energy International's equity investments and projects outside of the United States were $383 million in 2000, $367 million in 1999 and $333 million in 1998. In addition, NRG's wholly owned foreign assets ($796 million in 2000) contributed earnings of $30.1 million in 2000 and $0 in 1999 and 1998.*

19. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
(Thousands of dollars, except per share amounts)	*March 31, 2000*	*June 30, 2000*	*Sept. 30, 2000**	*Dec. 31, 2000**
Revenue***	$2,322,344	$2,460,509	$3,115,007	$3,693,936
Operating income	364,026	424,754	401,023	381,337
Income before extraordinary items				
Extraordinary items				
Net income	153,331	143,083	92,614	137,800
Earnings per share before extraordinary items:	152,271	142,022	91,554	136,740
Basic	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Diluted	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Earnings per share extraordinary items – basic & diluted		$ (0.04)	$ (0.02)	
Earnings per share after extraordinary items:				
Basic	$ 0.45	$ 0.42	$ 0.27	$ 0.40
Diluted	$ 0.45	$ 0.42	$ 0.27	$ 0.40

	Quarter Ended			
(Thousands of dollars, except per share amounts)	*March 31, 1999*	*June 30, 1999***	*Sept. 30,1999*	*Dec. 31, 1999***
Revenue***	$1,807,157	$1,654,399	$2,146,695	$2,207,292
Operating income	300,960	184,337	418,277	298,322
Net income	153,621	60,725	209,264	147,323
Earnings available for common stock	152,561	58,615	208,204	146,261
Earnings per share:				
Basic	$ 0.46	$ 0.18	$ 0.63	$ 0.43
Diluted	$ 0.46	$ 0.18	$ 0.63	$ 0.43

**2000 results include special charges related to merger costs and strategic alignment as discussed in Note 2 to the Financial Statements. Third-quarter results were reduced by approximately $201 million, or 43 cents per share. Fourth-quarter results were reduced by approximately $40 million, or 9 cents per share.*

***1999 results include two adjustments related to regulatory recovery of conservation program incentives. Second-quarter results were reduced by $35 million before taxes, or 7 cents per share, due to the disallowance of 1998 incentives. Fourth-quarter results were reduced by $22 million before taxes, or 4 cents per share, due to the reversal of all income recorded through the third quarter for 1999 electric conservation program incentives. In addition, 1999 fourth-quarter results include a pretax special charge of approximately $17 million, or 4 cents per share, to write off goodwill related to EMI acquisitions. Also, a pretax special charge of approximately $11 million, or 2 cents per share, was recorded in the fourth quarter of 1999 to write down an investment in CellNet common stock.*

****Trading revenues have been reclassified to reflect presentation on a gross basis for all periods.*

SHAREHOLDER INFORMATION

Headquarters
800 Nicollet Mall, Minneapolis, MN 55402

Internet Address
http://www.xcelenergy.com

Shareholders Information
Contact Wells Fargo Shareowners Services (Xcel Energy Inc. stock transfer agent) toll free at 1-877-778-6786.

Xcel Energy Direct Purchase Plan
Xcel Energy's Direct Purchase Plan, offered by prospectus, is a convenient way to purchase shares of Xcel Energy's common stock without payment of any brokerage commission or service charge. Contact Wells Fargo Shareowners Services, the plan administrator, at 1-877-778-6786 for a prospectus and authorization form.

Street-name Shareholders and Beneficial Owners
To receive Xcel Energy's quarterly report, contact Investor Relations at 1-877-914-9235.

Stock Exchange Listings and Ticker Symbol
Common stock is traded on the New York, Chicago and Pacific exchanges. Ticker symbol: XEL. NYSE lists some of Xcel Energy's preferred stock.

Form 10-K (The Annual Report to the Securities and Exchange Commission)
Available online at: http://www.xcelenergy.com or contact Investor Relations at 1-877-914-9235.

Investor Relations
Internet address: http://www.xcelenergy.com; Richard Kolkmann, Managing Director, Investor Relations, 612-215-4559 or Michael Pritchard, Director, Investor Relations, 612-215-4535

SHAREHOLDER INFORMATION

Schedule of Anticipated Dividend Record Dates and Payment Dates for 2001:

Declaration Dates	*Preferred Stock Record Dates*	*Payment Dates*	*Declaration Dates*	*Common Stock Record Dates*	*Payment Dates*
Dec. 13, 2000	Dec. 29, 2000	Jan. 15, 2001	Dec. 13, 2000	Jan. 2, 2001	Jan. 20, 2001
Jan. 24, 2001	March 30, 2001	April 15, 2001	March 21, 2001	April 2, 2001	April 20, 2001
April 25, 2001	June 29, 2001	July 15, 2001	June 27, 2001	July 9, 2001	July 20, 2001
Aug. 22, 2001	Sept. 28, 2001	Oct. 15, 2001	Aug. 22, 2001	Oct. 2, 2001	Oct. 20, 2001
Dec. 12, 2001	Dec. 31, 2001	Jan. 15, 2002			

FISCAL AGENTS

Xcel Energy Inc.

Transfer Agent, Registrar, Dividend Distribution, Common and Preferred Stocks
Wells Fargo Bank Minnesota, N.A.,161 North Concord Exchange, South St. Paul, MN 55075

Trustee-Bonds
Wells Fargo Bank Minnesota, N.A., Sixth St. and Marquette Ave., Minneapolis, MN 55479-0059

Coupon Paying Agents-Bonds
Wells Fargo Bank Minnesota, N.A., Minneapolis

The Xcel Energy board of directors includes (front row, left to right): Giannantonio Ferrari, A. Barry Hirschfeld, Albert Moreno, A. Patricia Sampson and Douglas Leatherdale. In the back row are (left to right): Wayne Brunetti, Margaret Preska, Allan Schuman, Rodney Slifer, C. Coney Burgess, David Christensen, W. Thomas Stephens, Roger Hemminghaus and James Howard.

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Giannantonio Ferrari *1, 4*
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Board Committees:
1. Audit
2. Compensation and Nominating
3. Finance
4. Operations and Nuclear

** Wayne H. Brunetti and James J. Howard are ex officio members of all committees.*

The Xcel Energy board of directors was formed in August 2000, upon completion of the merger.

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