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On Aug. 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. (Xcel Energy). Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act (PUHCA). 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 subsidiary of Xcel Energy named Northern States Power Co. 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. As a stock-for-stock exchange for shareholders of both companies, the merger was accounted for as a pooling-of-interests and, accordingly, amounts reported for periods prior to the merger have been restated for comparability with post-merger results.

Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are Northern States Power Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); Southwestern Public Service Co. (SPS); Black Mountain Gas Co. (BMG), which is in the process of being sold pending regulatory approval; and Cheyenne Light, Fuel and Power Co. (Cheyenne). They serve customers in portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. During 2002, Xcel Energy's regulated businesses also included Viking Gas Transmission Co. (Viking), which was sold on Jan. 17, 2003, and WestGas InterState Inc. (WGI), both interstate natural gas pipeline companies.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. (NRG), an independent power producer. Xcel Energy owned 100 percent of NRG at the beginning of 2000. About 18 percent of NRG was sold to the public in an initial public offering in the second quarter of 2000, leaving Xcel Energy with an 82-percent interest at Dec. 31, 2000. In March 2001, another 8 percent of NRG was sold to the public, leaving Xcel Energy with an interest of about 74 percent at Dec. 31, 2001. On June 3, 2002, Xcel Energy acquired the 26 percent of NRG held by the public so that it again held 100 percent ownership at Dec. 31, 2002. NRG is facing extreme financial difficulties. There is substantial doubt as to NRG's ability to continue as a going concern absent a restructuring through bankruptcy, and NRG will likely be the subject of a bankruptcy proceeding. See Notes 2, 3, 4 and 7 to the Consolidated Financial Statements.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (an international independent power producer).

FINANCIAL REVIEW

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying Consolidated Financial Statements and Notes. All note references refer to the Notes to Consolidated Financial Statements.

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "estimate," "expect," "objective," "outlook," "project," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including their impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership; structures that affect the speed and degree to which competition enters the electric and natural gas markets; the higher risk associated with Xcel Energy's nonregulated businesses compared with its regulated businesses; currency translation and transaction adjustments; risks associated with the California power market; the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Exhibit 99.01 to Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2002.

RESULTS OF OPERATIONS

Xcel Energy's earnings per share for the past three years were as follows:

Contribution to earnings per share	*2002*	*2001*	*2000*
Continuing operations before extraordinary items:			
Regulated utility	**$ 1.59**	$ 1.90	$ 1.20
NRG (including impairments and restructuring charges)	**(7.58)**	0.44	0.37
Other nonregulated/holding company (including tax benefits related to investment in NRG in 2002)	**1.63**	(0.21)	(0.06)
Income (loss) from continuing operations	**(4.36)**	2.13	1.51
Discontinued operations – NRG (see Note 3)	**(1.46)**	0.14	0.09
Extraordinary items – Regulated utility (see Note 15)	**–**	0.03	(0.06)
Total earnings (loss) per share – diluted	**$(5.82)**	$ 2.30	$ 1.54

Additional information on earnings contributions by operating segments are as follows:

Contribution to earnings per share	*2002*	*2001*	*2000*
Regulated utility (including extraordinary items):			
Electric utility	**$ 1.33**	$ 1.66	$ 1.03
Gas utility	**0.26**	0.24	0.17
Total regulated utility	**1.59**	1.90	1.20
NRG (including discontinued operations) (see Note 3)	**(9.04)**	0.58	0.46
Other nonregulated/holding company:			
Tax benefit related to investment in NRG	**1.85**	–	–
Other (see Note 21 for components)	**(0.22)**	(0.18)	(0.12)
Total earnings (loss) per share – diluted	**$(5.82)**	$ 2.30	$ 1.54

For more information on significant factors that had an impact on earnings, see below.

SIGNIFICANT FACTORS THAT IMPACTED 2002 RESULTS

Special Charges – Regulated Utility Regulated utility earnings from continuing operations were reduced by approximately 2 cents per share in 2002 due to a $5-million regulatory recovery adjustment for SPS and $9 million in employee separation costs associated with a restaffing initiative early in the year for utility and service company operations. See Note 2 to the Consolidated Financial Statements for further discussion of these items, which are reported as Special Charges in operating expenses.

Impairment and Financial Restructuring Charges – NRG NRG's losses from both continuing and discontinued operations were affected by charges recorded in 2002. Continuing operations included losses of approximately $7.07 per share in 2002 for asset impairment and disposal losses, and for other charges related mainly to its financial restructuring. These costs are reported as Special Charges and Write-downs and Disposal Losses from Investments in operating expenses, and are discussed further in Note 2 to the Consolidated Financial Statements. In addition, discontinued operations included losses of approximately $1.56 per share for asset impairments and disposal losses, and are discussed further in Note 3 to the Consolidated Financial Statements.

During 2002, NRG experienced credit-rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events led to impairment reviews of a number of NRG assets, which resulted in material write-downs in 2002. In addition to impairments of projects operating or under development, certain NRG projects were determined to be held for sale, and estimated losses on disposal for such projects were also recorded. These impairment charges, some of which related to equity investments, have reduced Xcel Energy's earnings for 2002 as follows: $6.29 of Special Charges in continuing operations, $0.51 of Losses on Disposal of Investments in continuing operations and $1.57 of impairment charges included in discontinued operations. As reported previously, there is substantial doubt as to NRG's ability to continue as a going concern, and NRG will likely be the subject of a bankruptcy proceeding.

NRG also expensed approximately $111 million in 2002 for incremental costs related to its financial restructuring and business realignment. These costs, which reduced 2002 earnings by 27 cents per share, include expenses for financial and legal advisors, contract termination costs, employee separation and other incremental costs incurred during the financial restructuring period. These costs also include a charge related to NRG's NEO landfill gas generation operations for the estimated impact of a dispute settlement with NRG's partner on the NEO project, Fortistar. Most of these costs were paid in 2002. See Note 2 to the Consolidated Financial Statements for discussion of accrued financial restructuring cost activity related to NRG.

Tax Benefit – NRG Investment As discussed in Note 11 to the Consolidated Financial Statements, it was determined in 2002 that NRG was no longer likely to be included in Xcel Energy's consolidated income tax group. Approximately $706 million has been recognized at one of Xcel Energy's nonregulated intermediate holding companies for the estimated tax benefits related to Xcel Energy's investment in NRG, based on the difference between book and tax bases of such investment. This estimated tax benefit increased 2002 annual results by $1.85 per share.

Other Nonregulated and Holding Companies Nonregulated and holding company earnings for 2002 were reduced by losses of approximately 6 cents per share for the combined effects of unusual items that occurred during the year. As discussed later, Xcel International recorded impairment losses for Argentina assets of 3 cents per share and disposal losses for Yorkshire Power of 2 cents per share, Planergy recorded gains from contract sales of 2 cents per share, losses were incurred on holding company debt of 2 cents per share, and incremental costs related to NRG financial restructuring activities of 1 cent per share were incurred at the holding company level.

SIGNIFICANT FACTORS THAT IMPACTED 2001 RESULTS

Regulated utility earnings were reduced by a net 1 cent per share from the combined effects of four unusual items that occurred during the year. Three of the items affected continuing operations, reducing earnings by 4 cents per share. The remaining item increased income from extraordinary items by 3 cents per share.

Conservation Incentive Recovery Regulated utility earnings from continuing operations in 2001 were increased by 7 cents per share due to a Minnesota Public Utilities Commission (MPUC) decision. In June 2001, the MPUC approved a plan allowing recovery of 1998 incentives associated with state-mandated programs for energy conservation. As a result, the previously recorded liabilities of approximately $41 million, including carrying charges, for potential refunds to customers were no longer required. The plan approved by the MPUC increased revenue by approximately $34 million and increased allowance for funds used during construction by approximately $7 million, increasing earnings by 7 cents per share for the second quarter of 2001. Based on the new MPUC policy and less uncertainty regarding conservation incentives to be approved, conservation incentives are being recorded on a current basis beginning in 2001.

Special Charges – Postemployment Benefits and Restaffing Costs Regulated utility earnings from continuing operations in 2001 were decreased by 4 cents per share due to a Colorado Supreme Court decision that resulted in a pretax write-off of $23 million of a regulatory asset related to deferred postemployment benefit costs at PSCo.

Also, regulated utility earnings from continuing operations were reduced by approximately 7 cents per share in 2001 due to $39 million of employee separation costs associated with a restaffing initiative late in the year for utility and service company operations. See Note 2 to the Consolidated Financial Statements for further discussion of these items, which are reported as Special Charges in operating expenses.

Extraordinary Items – Electric Utility Restructuring In 2001, extraordinary income of $18 million before tax, or 3 cents per share, was recorded related to the regulated utility business to reflect the impacts of industry restructuring developments for SPS. This represents a reversal of a portion of the 2000 extraordinary loss discussed later. For more information on SPS extraordinary items, see Note 15 to the Consolidated Financial Statements.

SIGNIFICANT FACTORS THAT IMPACTED 2000 RESULTS

Special Charges – Merger Costs During 2000, Xcel Energy expensed pretax special charges of $241 million, or 52 cents per share, for costs related to the merger between NSP and NCE. Of these special charges, approximately 44 cents per share were associated with the costs of merging regulated utility operations and 8 cents per share were associated with merger impacts on nonregulated and holding company activities other than NRG. See Note 2 to the Consolidated Financial Statements for more information on these merger-related costs reported as Special Charges.

Extraordinary Items – Electric Utility Restructuring In 2000, extraordinary losses of approximately $28 million before tax, or 6 cents per share, were recorded related to the regulated utility business for the expected discontinuation of regulatory accounting for SPS' generation business. For more information on SPS extraordinary items, see Note 15 to the Consolidated Financial Statements.

STATEMENT OF OPERATIONS ANALYSIS

Electric Utility and Commodity Trading Margins Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel cost recovery mechanisms for retail customers in several states, most fluctuations in energy costs do not materially affect electric utility margin. However, the fuel clause cost recovery in Colorado does not allow for complete recovery of all variable production expense, and cost changes can affect earnings. Electric utility margins reflect the impact of sharing energy costs and savings relative to a target cost per delivered kilowatt-hour and certain trading margins under the incentive cost adjustment (ICA) ratemaking mechanism in Colorado. In addition to the ICA, Colorado has other adjustment clauses that allow certain costs to be recovered from retail customers.

Xcel Energy has three distinct forms of wholesale sales: short-term wholesale, electric commodity trading and natural gas commodity trading. Short-term wholesale refers to electric sales for resale, which are associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Electric and natural gas commodity trading refers to the sales for resale activity of purchasing and reselling electric and natural gas energy to the wholesale market.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota (electric), PSCo (electric) and e prime (natural gas). Margins from electric trading activity, conducted at NSP-Minnesota and PSCo, are partially redistributed to other operating utilities of Xcel Energy, pursuant to a joint operating agreement (JOA) approved by the Federal Energy Regulatory Commission (FERC). Trading margins reflect the impact of sharing certain trading margins under the ICA. Trading revenues, as discussed in Note 1 to the Consolidated Financial Statements, are reported net (i.e., margins) in the Consolidated Statements of Operations. Trading revenue and costs associated with NRG's operations are included in nonregulated margins. The following table details the revenue and margin for base electric utility, short-term wholesale and electric and natural gas trading activities.

(Millions of dollars)	*Base Electric Utility*	*Short-Term Wholesale*	*Electric Commodity Trading*	*Natural Gas Commodity Trading*	*Intercompany Eliminations*	*Consolidated Totals*
2002						
Electric utility revenue	**$ 5,232**	**$ 203**	**$ –**	**$ –**	**$ –**	**$ 5,435**
Electric fuel and purchased power – utility	**(2,029)**	**(170)**	**–**	**–**	**–**	**(2,199)**
Electric and natural gas trading revenue – gross	**–**	**–**	**1,529**	**1,898**	**(71)**	**3,356**
Electric and natural gas trading costs	**–**	**–**	**(1,527)**	**(1,892)**	**71**	**(3,348)**
Gross margin before operating expenses	**$ 3,203**	**$ 33**	**$ 2**	**$ 6**	**$ –**	**$ 3,244**
Margin as a percentage of revenue	**61.2%**	**16.3%**	**0.1%**	**0.3%**	**–**	**36.9%**
2001						
Electric utility revenue	$ 5,607	$ 788	$ –	$ –	$ –	$ 6,395
Electric fuel and purchased power – utility	(2,559)	(613)	–	–	–	(3,172)
Electric and natural gas trading revenue – gross	–	–	1,337	1,938	(88)	3,187
Electric and natural gas trading costs	–	–	(1,268)	(1,918)	88	(3,098)
Gross margin before operating expenses	$ 3,048	$ 175	$ 69	$ 20	$ –	$ 3,312
Margin as a percentage of revenue	54.4%	22.2%	5.2%	1.0%	–	34.6%
2000						
Electric utility revenue	$ 5,107	$ 567	$ –	$ –	$ –	$ 5,674
Electric fuel and purchased power – utility	(2,106)	(475)	–	–	–	(2,581)
Electric and natural gas trading revenue – gross	–	–	819	1,297	(54)	2,062
Electric and natural gas trading costs	–	–	(788)	(1,287)	54	(2,021)
Gross margin before operating expenses	$ 3,001	$ 92	$ 31	$ 10	$ –	$ 3,134
Margin as a percentage of revenue	58.8%	16.2%	3.8%	0.8%	–	40.5%

2002 Comparison to 2001 Base electric utility revenue decreased $375 million, or 6.7 percent, while electric utility margins, primarily retail, increased approximately $155 million, or 5.1 percent, in 2002, compared with 2001. Base electric revenues decreased largely due to decreased recovery of fuel and purchased power costs driven by declining fuel costs in 2002. The higher base electric margins in the year reflect lower unrecovered costs, due in part to resetting the base-cost recovery at PSCo in January 2002. In 2001, PSCo's allowed recovery was approximately $78 million less than its actual costs, while in 2002 its allowed recovery was approximately $29 million more than its actual cost. For the year, higher accrued conservation revenues, sales growth and more favorable temperatures also contributed to the higher electric margins and partially offset the lower base electric revenue. Lower wholesale capacity sales in Texas, as well as the impact of the conservation incentive adjustment in Minnesota in 2001, as discussed previously, partially offset the increased margins and contributed to the lower revenues.

Short-term wholesale margins consist of asset-based trading activity. Electric and natural gas commodity trading activity margins consist of non-asset-based trading activity. Short-term wholesale and electric and natural gas commodity trading sales margins decreased an aggregate of approximately $223 million, or 84.5 percent, in 2002, compared with 2001. The decrease in short-term wholesale and electric commodity trading margin reflects lower power prices and less favorable market conditions. The decrease in natural gas commodity trading margin reflects reduced market opportunities.

2001 Comparison to 2000 Base electric utility revenue increased by approximately $500 million, or 9.8 percent, in 2001. Base electric utility margin increased by approximately $47 million, or 1.6 percent, in 2001. These revenue and margin increases were due to sales growth, weather conditions in 2001 and the recovery of conservation incentives in Minnesota. Increased conservation incentives, including the resolution of the 1998 dispute, as discussed previously, and accrued 2001 incentives, increased revenue and margin by $49 million. More favorable weather during 2001 increased revenue by approximately $23 million and margin by approximately $13 million. These increases were partially offset by increases in fuel and purchased power costs, which are not completely recoverable from customers in Colorado due to various cost-sharing mechanisms. Revenue and margin also were reduced in 2001 by approximately $30 million due to rate reductions in various jurisdictions agreed to as part of the merger approval process, compared with $10 million in 2000.

Short-term wholesale revenue increased by approximately $221 million, or 39 percent, in 2001. Short-term wholesale margin increased $83 million, or 90.2 percent, in 2001. These increases are due to the expansion of Xcel Energy's wholesale marketing operations and favorable market conditions for the first six months of 2001, including strong prices in the western markets, particularly before the establishment of price caps and other market changes.

Electric and natural gas commodity trading margins, including proprietary electric trading (i.e., not in electricity produced by Xcel Energy's own generating plants) and natural gas trading, increased approximately $48 million for the year ended Dec. 31, 2001, compared with the same period in 2000. The increase reflects an expansion of Xcel Energy's trading operations and favorable market conditions, including strong prices in the western markets, particularly before the establishment of price caps and other market changes.

Natural Gas Utility Margins The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin.

(Millions of dollars)	*2002*	*2001*	*2000*
Natural gas utility revenue	**$ 1,398**	$ 2,053	$ 1,469
Cost of natural gas purchased and transported	**(852)**	(1,518)	(948)
Natural gas utility margin	**$ 546**	$ 535	$ 521

2002 Comparison to 2001 Natural gas utility revenue decreased by $655 million, or 31.9 percent, while natural gas margins increased by $11 million, or 2.1 percent. Natural gas revenue decreased largely due to decreases in the cost of natural gas, which are generally passed through to customers. Natural gas utility margin increased due primarily to more favorable temperatures and sales growth.

2001 Comparison to 2000 Natural gas utility revenue increased by approximately $584 million, or 39.8 percent, for 2001, primarily due to increases in the cost of natural gas, which are largely passed on to customers and recovered through various rate adjustment clauses in most of the jurisdictions in which Xcel Energy operates. Natural gas utility margin increased by approximately $14 million, or 2.7 percent, for 2001 due to sales growth and a rate increase in Colorado. These natural gas revenue and margin increases were partially offset by the impact of warmer temperatures in 2001, which decreased natural gas revenue by approximately $38 million and natural gas margin by approximately $16 million.

Nonregulated Operating Margins The following table details the changes in nonregulated revenue and margin included in continuing operations.

(Millions of dollars)	*2002*	*2001*	*2000*
Nonregulated and other revenue	**$2,611**	$2,580	$1,856
Earnings from equity investments	**72**	217	183
Nonregulated cost of goods sold	**(1,361)**	(1,319)	(877)
Nonregulated margin	**$ 1,322**	$ 1,478	$ 1,162

2002 Comparison to 2001 Nonregulated revenue from continuing operations increased slightly in 2002, reflecting growth from the full-year impact of NRG's 2001 generating facility acquisitions but partially offset by lower market prices. Nonregulated margin from continuing operations decreased in 2002, due to decreased equity earnings. Earnings from equity investments for 2002 decreased compared with 2001, primarily due to decreased equity earnings from NRG's West Coast Power project, which experienced less favorable long-term contracts and higher uncollectible receivables.

2001 Comparison to 2000 Nonregulated revenue and margin from continuing operations increased in 2001, largely due to NRG's acquisition of generating facilities, increased demand for electricity, market dynamics, strong performance from existing assets and higher market prices for electricity. Earnings from equity investments for 2001 increased compared with 2000, primarily due to increased equity earnings from NRG projects, which offset lower equity earnings from Yorkshire Power. As a result of a sales agreement to sell most of its investment in Yorkshire Power, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001.

Non-Fuel Operating Expense and Other Items Other utility operating and maintenance expense for 2002 decreased by approximately $4 million, or 0.3 percent. The decreased costs reflect lower incentive compensation and other employee benefit costs, as well as lower staffing levels in corporate areas. These decreases were substantially offset by higher plant outage and property insurance costs, in addition to inflationary factors such as market wage increases.

Other utility operating and maintenance expense for 2001 increased by approximately $60 million, or 4.1 percent, compared with 2000. The change is largely due to increased plant outages, higher nuclear operating costs, bad debt reserves reflecting higher energy prices, increased costs due to customer growth and higher performance-based incentive costs.

Other nonregulated operating and maintenance expenses for continuing operations increased $111 million in 2002 and increased $143 million in 2001. These expenses are included in the results for each nonregulated subsidiary, as discussed later.

Depreciation and amortization expense increased $131 million, or 14.5 percent, in 2002 and $140 million, or 18.2 percent, in 2001, primarily due to acquisitions of generating facilities by NRG and additions to utility plant. Higher NRG depreciation expense accounted for $87 million of the increase in 2002.

Interest income was higher in 2002 and 2001 due to higher cash balances at NRG in both years and to interest on affiliate loans in 2001.

Other income was higher in 2002 and 2001 due mainly to a gain on the sale of nonregulated property and PSCo assets.

Other expense increased in 2002 due largely to variations in currency exchange losses at NRG.

Interest expense increased $152 million, or 20.8 percent, in 2002 and $114 million, or 18.5 percent, in 2001, primarily due to increased debt of NRG. In addition, long-term debt was refinanced at higher interest rates during 2002. Higher NRG interest expense accounted for $105 million of the increase in 2002.

Income tax expense decreased by approximately $959 million in 2002, compared with 2001. Nearly all of this decrease relates to NRG's 2002 losses and the change in tax filing status for NRG effective in the third quarter of 2002, as discussed in Note 11 to the Consolidated Financial Statements. NRG is now in a tax operating loss carry forward position and is no longer assumed to be part of Xcel Energy's consolidated tax group. The effective tax rate for continuing operations, excluding minority interest and before extraordinary items, was 27.3 percent for the year ended Dec. 31, 2002, and 28.8 percent for the same period in 2001. The decrease in the effective rate between years reflects a nominal tax rate at NRG due to its loss carry forward position. Partially offsetting the NRG tax rate decrease is the impact of a one-time adjustment to recognize tax benefits from Xcel Energy's investment in NRG, as discussed in Note 11 to the Consolidated Financial Statements. The effective tax rate for the regulated utility business and operations other than NRG was significantly lower in 2002, compared with 2001, due to the benefit recorded on the investment in NRG and the changes in the items listed in the rate reconciliation in Note 11.

Weather Xcel Energy's earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase expenses, which may not be fully recoverable. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses, which affects overall results. The following summarizes the estimated impact on the earnings of the utility subsidiaries of Xcel Energy due to temperature variations from historical averages:

– weather in 2002 increased earnings by an estimated 6 cents per share;
– weather in 2001 had minimal impact on earnings per share; and
– weather in 2000 increased earnings by an estimated 1 cent per share.

NRG RESULTS

Contribution to Xcel Energy's earnings per share	***2002***	*2001*	*2000*
Continuing NRG operations:			
Operations before tax credits, special charges and disposal losses	**$ (0.54)**	$ 0.49	$ 0.35
Tax credits	**–**	0.14	0.10
Special charges – asset impairments (Note 2)	**(6.29)**	–	–
Special charges – financial restructuring and NEO (Note 2)	**(0.27)**	–	–
Write-downs and disposal losses from equity investments (Note 2)	**(0.51)**	–	–
Income (loss) from continuing NRG operations	**(7.61)**	0.63	0.45
Discontinued NRG operations (Note 3)	**(1.46)**	0.14	0.09
Total NRG earnings (loss) per share	**(9.07)**	0.77	0.54
Minority shareholder interest	**0.03**	(0.19)	(0.08)
NRG contribution to Xcel Energy	**$ (9.04)**	$ 0.58	$ 0.46

NRG Continuing Operations and Tax Credits As previously stated, NRG is facing extreme financial difficulties, and there is substantial doubt as to NRG's ability to continue as a going concern. During 2002, NRG's continuing operations, excluding impacts of asset impairments and disposals and restructuring costs, experienced significant losses compared with 2001. The 2002 losses are primarily attributable to NRG's North American operations, which experienced significant reductions in domestic energy and capacity sales and an overall decrease in power pool prices and related spark spreads. During 2002, an additional reserve for uncollectible receivables in California was established by West Coast Power, which reduced NRG's equity earnings by approximately $29 million, after tax. West Coast Power's 2002 income also was lower than 2001 due to less-favorable contracts and reductions in sales of energy and capacity. In addition, increased administrative costs, depreciation and interest expense from completed construction costs also contributed to the less-than-favorable results for NRG in 2002. Partially off-setting these earnings reductions was the recognition, in the fourth quarter of 2002, of approximately $51 million of additional revenues related to the contractual termination related to NRG's Indian River project.

On a stand-alone basis, NRG does not have the ability to recognize all tax benefits that may ultimately accrue from its losses incurred in 2002, thus increasing the overall loss from continuing operations. In addition to losing the ability to recognize all tax benefits for operating losses, NRG in 2002 also lost the ability to utilize tax credits generated by its energy projects. These lower tax credits account for a portion of the decreased earnings contribution of NRG compared with results in 2001 and 2000, which included income related to recognition of tax credits.

NRG's earnings for 2001 increased primarily due to new acquisitions in Europe and North America, as well as a full year of operation in 2001 of acquisitions made in the fourth quarter of 2000. In addition, NRG's 2001 earnings reflected a reduction in the overall effective tax rate and mark-to-market gains related to SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activity." The overall reduction in tax rates in 2001 was primarily due to higher energy credits, the implementation of state tax planning strategies and a higher percentage of NRG's overall earnings derived from foreign projects in lower tax jurisdictions.

NRG Special Charges – Impairments and Financial Restructuring As discussed previously, both the continuing and discontinued operations of NRG in 2002 included material losses for asset impairments and estimated disposal losses. Also, NRG recorded other special charges in 2002, mainly for incremental costs related to its financial restructuring and business realignment. See Notes 2 and 3 to the Consolidated Financial Statements for further discussion of NRG's special charges and discontinued operations, respectively.

OTHER NONREGULATED SUBSIDIARIES AND HOLDING COMPANY RESULTS

Contribution to Xcel Energy's earnings per share	*2002*	*2001*	*2000*
Xcel International	**$(0.05)**	$(0.02)	$ 0.09
Eloigne Company	**0.02**	0.03	0.02
Seren Innovations	**(0.07)**	(0.08)	(0.07)
Planergy International	**–**	(0.04)	(0.08)
e prime	**–**	0.02	(0.02)
Financing costs and preferred dividends	**(0.11)**	(0.11)	(0.07)
Other nonregulated/holding company results	**(0.01)**	0.02	0.01
Subtotal – nonregulated/holding co. excluding tax benefit	**(0.22)**	(0.18)	(0.12)
Tax benefit from investment in NRG (Note 11)	**1.85**	–	–
Total nonregulated/holding company earnings per share	**$ 1.63**	$(0.18)	$(0.12)

Xcel International Xcel International currently comprises primarily power generation projects in Argentina, and previously included an investment in Yorkshire Power.

In December 2002, a subsidiary of Xcel Argentina decided it would no longer fund one of its power projects in Argentina and defaulted on its loan agreements. The default is not material to Xcel Energy. However, this decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of Xcel International's investment. An impairment write-down of approximately $13 million, or 3 cents per share, was recorded in 2002.

In August 2002, Xcel Energy announced it had sold its 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. The sale of the 5.25-percent interest resulted in an after-tax loss of $8.3 million, or 2 cents per share, in 2002. The loss is included in write-downs and disposal losses from investments on the Consolidated Statements of Operations. Xcel Energy and American Electric Power Co. initially each held a 50-percent interest in Yorkshire, a UK retail electricity and natural gas supplier and electricity distributor, before selling 94.75 percent of Yorkshire to Innogy Holdings plc in April 2001. As a result of this sales agreement, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001. For more information, see Note 3 to the Consolidated Financial Statements.

Eloigne Company Eloigne invests in affordable housing that qualifies for Internal Revenue Service tax credits. Eloigne's earnings contribution declined slightly in 2002 as tax credits on mature affordable housing projects began to decline. The actual decline in Eloigne's net income in 2002, compared with 2001, was only $716,000, with 2002 earnings representing 2.1 cents per share and 2001 earnings representing 2.5 cents per share.

Seren Innovations Seren operates a combination cable television, telephone and high-speed Internet access system in St. Cloud, Minn., and Contra Costa County, California. Operation of its broadband communications network has resulted in losses. Seren projects improvement in its operating results with positive cash flow anticipated in 2005, upon completion of its build-out phase, and a positive earnings contribution anticipated in 2008.

Planergy International Planergy, a wholly owned subsidiary of Xcel Energy, provides energy management services. Planergy's results for 2002 improved, largely due to gains from the sale of a portfolio of energy management contracts, which increased earnings by nearly 2 cents per share.

Planergy's results for 2000 were reduced by special charges of 4 cents per share for the write-offs of goodwill and project development costs.

e prime e prime's results for the year ended Dec. 31, 2001, reflect the favorable structure of its contractual portfolio, including natural gas storage and transportation positions, structured products and proprietary trading in natural gas markets. e prime's earnings were lower in 2002, and higher in 2001, due to varying natural gas commodity trading margins, as discussed previously.

e prime's results for 2000 were reduced by special charges of 2 cents per share for contractual obligations and other costs associated with post-merger changes in the strategic operations and related revaluations of e prime's energy marketing business.

Financing Costs and Preferred Dividends Nonregulated results include interest expense and preferred dividends, which are incurred at the Xcel Energy and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

In November 2002, the Xcel Energy holding company issued temporary financing, which included detachable options for the purchase of Xcel Energy notes, which are convertible to Xcel Energy common stock. This temporary financing was replaced with longer-term holding company financing in late November 2002. Costs incurred to redeem the temporary financing included a redemption premium of $7.4 million, $5.2 million of debt discount associated with the detachable option and other issuance costs, which increased financing costs and reduced 2002 earnings by 2 cents per share.

Other Certain costs related to NRG's restructuring are being incurred at the holding company level. Approximately $5 million of such costs were incurred in 2002, which reduced earnings by approximately 1 cent per share.

Other nonregulated results for 2000, which include the activity of several nonregulated subsidiaries, were reduced by merger-related special charges of 2 cents per share. These special charges include $10 million in asset write-downs and losses resulting from various other nonregulated business ventures that are no longer being pursued after the Xcel Energy merger.

FACTORS AFFECTING RESULTS OF OPERATIONS

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions. In addition, Xcel Energy's nonregulated businesses have adversely affected Xcel Energy's earnings in 2002. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by the following factors:

Impact of NRG Financial Difficulties NRG is experiencing severe financial difficulties, resulting primarily from declining credit ratings and lower prices for power. These financial difficulties have caused NRG to miss several scheduled payments of interest and principal on its bonds and incur approximately $3.1 billion in asset impairment charges. In addition, as a result of being downgraded, NRG was required to post cash collateral ranging from $1.1 billion to $1.3 billion. NRG has been unable to post this cash collateral and, as a result, is in default on various obligations. Furthermore, in November 2002, lenders to NRG accelerated approximately $1.1 billion of NRG's debt, rendering the debt immediately due and payable. In February 2003, lenders to NRG accelerated an additional $1 billion of debt. NRG does not contemplate making any principal or interest payments on its corporate-level debt pending the restructuring of its obligations, and is in default under various debt instruments. As a consequence of the defaults, the lenders are able to seek to enforce their remedies, if they so choose, and that would likely lead to a bankruptcy filing by NRG. NRG continues to work with its lenders and bondholders on a comprehensive financial restructuring plan. See further discussion of potential NRG bankruptcy and financial restructuring under Liquidity and Capital Resources and in Notes 4 and 18 to the Consolidated Financial Statements.

Subsequent to its credit downgrade in July 2002, NRG experienced losses as follows in 2002:

(Millions of dollars)	*Third Quarter*	*Fourth Quarter*
Net losses from NRG:		
Special charges – asset impairments	$(2,466)	$ (79)
Special charges – financial restructuring and other costs	(34)	(21)
Write-downs and losses on equity method investments	(118)	(74)
Other income (loss) from continuing operations, including income tax effects	140	(176)
NRG loss from continuing operations	(2,478)	(350)
Discontinued operations – asset impairments	(600)	–
Discontinued operations – other	23	9
Net NRG loss for period	$(3,055)	$(341)

These NRG losses have reduced Xcel Energy's retained earnings to a deficit as of Dec. 31, 2002. NRG is expected to continue to experience material losses into 2003, pending a successful financial restructuring and increased power prices. NRG's losses in 2003 may include further asset impairments, losses from asset disposals and financial restructuring costs as NRG continues its financial restructuring and decisions are made to realign NRG's business operations and divest operating assets. In addition, the impact of any settlement with NRG's creditors regarding the financial restructuring of NRG also may impact Xcel Energy's operating results and retained earnings by material amounts that will not be determinable until settlement terms are reached. See Note 4 to the Consolidated Financial Statements for a discussion of a preliminary settlement with NRG's creditors. As discussed later, Xcel Energy is unable, without SEC approval under PUHCA, to declare dividends on its common stock until consolidated retained earnings are positive, and continuing NRG financial impacts may continue to limit the ability of Xcel Energy to declare and pay dividends.

In the event that NRG's financial situation ultimately results in a bankruptcy filing, there may be additional impacts on Xcel Energy's financial condition and results of operations. See the Xcel Energy Impacts under the Other Liquidity and Capital Resource Considerations section later in Management's Discussion and Analysis, and Note 4 to the Consolidated Financial Statements for further discussion of the possible effects of an NRG bankruptcy filing on Xcel Energy.

General Economic Conditions The slower U.S. economy, and the global economy to a lesser extent, may have a significant impact on Xcel Energy's operating results. Current economic conditions have resulted in a decline in the forward price curve for energy and decreased commodity-trading margins. In addition, certain operating costs, such as insurance and security, have increased due to the economy, terrorist activity and war. Management cannot predict the impact of a continued economic slowdown, fluctuating energy prices or war. However, Xcel Energy could experience a material adverse impact to its results of operations, future growth or ability to raise capital due to a weakened economy or war.

Sales Growth In addition to weather impacts, customer sales levels in Xcel Energy's regulated utility businesses can vary with economic conditions, customer usage patterns and other factors. Weather-normalized sales growth for retail electric utility customers was estimated to be 1.8 percent in 2002 compared with 2001, and 1.0 percent in 2001 compared with 2000. Weather-normalized sales growth for firm natural gas utility customers was estimated to be approximately the same in 2002 compared with 2001, and 2.6 percent in 2001 compared with 2000. We are projecting that 2003 weather-normalized sales growth in 2003 compared with 2002 will be 1.5 to 2.0 percent for retail electric utility customers and 2.5 to 3.0 percent for firm natural gas utility customers.

Utility Industry Changes The structure of the electric and natural gas utility industry has been subject to change. Merger and acquisition activity over the past few years has been significant as utilities combine to capture economies of scale or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide nondiscriminatory access to the use of their transmission systems.

In December 2001, the FERC approved Midwest Independent Transmission System Operator, Inc. (MISO) as the Midwest independent system operator responsible for operating the wholesale electric transmission system. Accordingly, in compliance with the FERC's Order No. 2000, Xcel Energy turned over operational control of its transmission system to the MISO in January 2002.

Some states had begun to allow retail customers to choose their electricity supplier, and many other states were considering retail access proposals. However, the experience of the state of California in instituting competition, as well as the bankruptcy filing of Enron, have caused indefinite delays in most industry restructuring.

Xcel Energy cannot predict the outcome of restructuring proceedings in the electric utility jurisdictions it serves at this time. The resolution of these matters may have a significant impact on Xcel Energy's financial position, results of operations and cash flows.

California Power Market NRG operates in the wholesale power market in California. See Note 18 to the Consolidated Financial Statements for a description of lawsuits against NRG and other power producers and marketers involving the California electricity markets. Xcel Energy and NRG have fully reserved for their uncollected receivables related to the California power market.

Critical Accounting Policies Preparation of the Consolidated Financial Statements and related disclosures in compliance with generally accepted accounting principles (GAAP) requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the Consolidated Financial Statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the Consolidated Financial Statements and related disclosures, even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most significant to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policy	*Judgments/Uncertainties Affecting Application*	*See Additional Discussion At*
Asset Valuation NRG Seren Argentina	– Regional economic conditions affecting asset operation, market prices and related cash flows – Foreign currency valuation changes – Regulatory and political environments and requirements – Levels of future market penetration and customer growth	Management's Discussion and Analysis: Results of Operations Management's Discussion and Analysis: Factors Affecting Results of Operations Impacts of NRG Financial Difficulties Impact of Other Nonregulated Investments Notes to Consolidated Financial Statements Notes 2, 3 and 18
NRG Financial Restructuring	– Terms negotiated to settle NRG's obligations to its creditors – Ownership interest in and control of NRG and related ability to continue consolidating NRG as a subsidiary – Impacts of court decisions in future bankruptcy proceedings, including any obligations of Xcel Energy	Management's Discussion and Analysis: Liquidity and Capital Resources NRG Financial Issues Xcel Energy Impacts Notes to Consolidated Financial Statements Notes 4 and 18
Income Tax Accruals	– Application of tax statutes and regulations to transactions – Anticipated future decisions of tax authorities – Ability of tax authority decisions/positions to withstand legal challenges and appeals – Ability to realize tax benefits through carrybacks to prior periods or carryovers to future periods	Management's Discussion and Analysis: Factors Affecting Results of Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 11 and 18
Benefit Plan Accounting	– Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition – Interest rates used in valuing benefit obligation – Actuarial period selected to recognize deferred investment gains and losses	Management's Discussion and Analysis: Factors Affecting Results of Operations Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements Notes 1 and 13
Regulatory Mechanisms and Cost Recovery	– External regulator decisions, requirements and regulatory environment – Anticipated future regulatory decisions and their impact – Impact of deregulation and competition on ratemaking process and ability to recover costs	Management's Discussion and Analysis: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to Consolidated Financial Statements Notes 1, 18 and 20
Environmental Issues	– Approved methods for cleanup – Responsible party determination – Governmental regulations and standards – Results of ongoing research and development regarding environmental impacts	Management's Discussion and Analysis: Factors Affecting Results of Operations Environmental Matters Notes to Consolidated Financial Statements Notes 1 and 18
Uncollectible Receivables	– Economic conditions affecting customers, suppliers and market prices – Regulatory environment and impact of cost recovery constraints on customer financial condition – Outcome of litigation and regulatory proceedings	Management's Discussion and Analysis: Factors Affecting Results of Operations California Power Market Notes to Consolidated Financial Statements Notes 1 and 18
Nuclear Plant Decommissioning and Cost Recovery	– Costs of future decommissioning – Availability of facilities for waste disposal – Approved methods for waste disposal – Useful lives of nuclear power plants – Future recovery of plant investment and decommissioning costs	Notes to Consolidated Financial Statements Notes 1, 18 and 19

Pension Plan Costs and Assumptions Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future, and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. Note 13 to the Consolidated Financial Statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs have been increasing in recent years, and are expected to increase further over the next several years, due to lower than expected investment returns experienced and decreases in interest rates used to discount benefit obligations. Investment returns in 2000 and 2001 were below the assumed level of 9.5 percent, and interest rates have declined from the 7.5-percent to 8-percent levels used in 1999 and 2000 cost determinations to 7.25 percent used in 2002. Xcel Energy continually reviews its pension assumptions, and in 2003, expects to change the investment return assumption to 9.25 percent and the discount rate assumption to 6.75 percent.

Xcel Energy bases its investment return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. These include equity investments, such as corporate common stocks; fixed-income investments, such as corporate bonds; and U.S. Treasury securities and nontraditional investments, such as timber or real estate partnerships. In reaching a return assumption, Xcel Energy considers the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts in the marketplace. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 12.6 percent, in excess of the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long term. The target and 2002 mix of assets among these portfolio components is discussed in Note 13 to the Consolidated Financial Statements. The Xcel Energy portfolio is heavily weighted toward equity securities, and includes nontraditional investments that can provide a higher-than-average return. However, as is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels actually achieved by pension assets in any year. Xcel Energy lowered the 2003 pension investment return assumptions to reflect the changing expectations of investment experts in the marketplace.

The investment gains or losses resulting from the difference between the expected pension returns assumed on smoothed or "market-related" asset levels and actual returns earned is deferred in the year the difference arises and recognized over the subsequent five-year period. This gain or loss recognition occurs by using a five-year moving-average value of pension assets to measure expected asset returns in the cost determination process, and by amortizing deferred investment gains or losses over the subsequent five-year period. Based on the use of average market-related asset values, and considering the expected recognition of past investment gains and losses over the next five years, achieving the assumed rate of asset return of 9.25 percent in each future year and holding other assumptions constant, we currently project that the pension costs recognized by Xcel Energy for financial reporting purposes will increase from a credit, or negative expense, of $84 million in 2002 to a credit of $45 million in 2003, a credit of $20 million in 2004, and a net expense of $20 million in 2005. Pension costs are currently a credit due to the recognized investment asset returns exceeding the other pension cost components, such as benefits earned for current service and interest costs for the effects of the passage of time on discounted obligations.

Xcel Energy bases its discount rate assumption on benchmark interest rates quoted by an established credit rating agency, Moody's Investors Service (Moody's), and has consistently benchmarked the interest rate used to derive the discount rate to the movements in the long-term corporate bond indices for bonds rated AAA through BAA by Moody's, which have a period to maturity comparable to our projected benefit obligations. At Dec. 31, 2002, the annualized Moody's Aa index rate, roughly in the middle of the AAA and BAA range, was 6.63 percent, which when rounded to the nearest quarter-percent rate, as is our policy, resulted in our 6.75-percent pension discount rate at year-end 2002. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2003 pension cost determinations.

If Xcel Energy were to use alternative assumptions for pension cost determinations, a 1-percent change would result in the following impacts on the estimated pension costs recognized by Xcel Energy for financial reporting purposes:

- a 1-percent higher rate of return, 10.25 percent, would decrease 2003 pension costs by $22 million
- a 1-percent lower rate of return, 8.25 percent, would increase 2003 pension costs by $22 million
- a 1-percent higher discount rate, 7.75 percent, would decrease 2003 pension costs by $8 million
- a 1-percent lower discount rate, 5.75 percent, would increase 2003 pension costs by $12 million

Alternative assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in recent years for Xcel Energy's pension plans, and do not require funding in 2003. Assuming future asset return levels equal the actuarial assumption of 9.25 percent for the years 2003-2005, then under current funding regulations we project that no cash funding would be required for 2004, $35 million in funding would be required for 2005 and $54 million in funding would be required for 2006. Actual performance can affect these funding requirements significantly. If the actual return level is 0 percent in 2003 and 2004, which assumes a continued downturn in the financial markets, and 9.25 percent in 2005 then the 2004 cash-funding requirement would still be zero. However, the

2005 funding requirement would increase to $60 million, and 2006 funding required would be $70 million. Current funding regulations are under legislative review in 2003, and if not retained in their current form, could change these funding requirements materially.

Regulation Xcel Energy is a registered holding company under the PUHCA. As a result, Xcel Energy, its utility subsidiaries and certain of its nonutility subsidiaries are subject to extensive regulation by the SEC under the PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties and intra-system sales of certain goods and services. In addition, the PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. See further discussion of financing restrictions under Liquidity and Capital Resources.

The electric and natural gas rates charged to customers of Xcel Energy's utility subsidiaries are approved by the FERC and the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Because comprehensive rate changes are requested infrequently in some states, changes in operating costs can affect Xcel Energy's financial results. In addition to changes in operating costs, other factors affecting rate filings are sales growth, conservation and demand-side management efforts, and the cost of capital.

Most of the retail rate schedules for Xcel Energy's utility subsidiaries provide for periodic adjustments to billings and revenues to allow for recovery of changes in the cost of fuel for electric generation, purchased energy, purchased natural gas and, in Minnesota and Colorado, conservation and energy management program costs. In Minnesota and Colorado, changes in electric capacity costs are not recovered through these rate adjustment mechanisms. For Wisconsin electric operations, where automatic cost-of-energy adjustment clauses are not allowed, the biennial retail rate review process and an interim fuel-cost hearing process provide the opportunity for rate recovery of changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In Colorado, PSCo has an ICA mechanism that allows for an equal sharing among customers and shareholders of certain fuel and energy costs and certain gains and losses on trading margins.

Regulated public utilities are allowed to record as regulatory assets certain costs that are expected to be recovered from customers in future periods and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, nonregulated enterprises would expense these costs and recognize the income in the current period. If restructuring or other changes in the regulatory environment occur, Xcel Energy may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material adverse effect on Xcel Energy's results of operations in the period the write-off is recorded.

At Dec. 31, 2002, Xcel Energy reported on its balance sheet regulatory assets of approximately $404 million and regulatory liabilities of approximately $297 million that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. Xcel Energy currently does not expect to write off any stranded costs unless market price levels change or cost levels increase above market price levels. See Notes 1 and 20 to the Consolidated Financial Statements for further discussion of regulatory deferrals.

Merger Rate Agreements As part of the merger approval process, Xcel Energy agreed to reduce its rates in several jurisdictions. The discussion below summarizes the rate reductions in Colorado, Minnesota, Texas and New Mexico.

As part of the merger approval process in Colorado, PSCo agreed to:
- reduce its retail electric rates by an annual rate of $11 million for the period of August 2000 through July 2002;
- file a combined electric and natural gas rate case in 2002, with new rates effective January 2003;
- cap merger costs associated with the electric operations at $30 million and amortize the merger costs for ratemaking purposes through 2002;
- extend its ICA mechanism through Dec. 31, 2002, with an increase in the ICA base rate from $12.78 per megawatt-hour to a rate based on 2001 actual costs;
- continue the electric performance-based regulatory plan (PBRP) and the electric quality service plan (QSP) currently in effect through 2006, with modifications to cap electric earnings at a 10.5-percent return on equity for 2002, to reflect no earnings sharing in 2003 since new base rates would have recently been established, and to increase potential bill credits if quality standards are not met; and
- develop a QSP for the natural gas operations to be effective for calendar years 2002 through 2007.

As part of the merger approval process in Minnesota, NSP-Minnesota agreed to:
- reduce its Minnesota electric rates by $10 million annually through 2005;
- not increase its electric rates through 2005, except under limited circumstances;
- not seek recovery of certain merger costs from customers; and
- meet various quality standards.

As part of the merger approval process in Texas, SPS agreed to:

- guarantee annual merger savings credits of approximately $4.8 million and amortize merger costs through 2005;
- retain the current fuel-recovery mechanism to pass along fuel-cost savings to retail customers; and
- comply with various service quality and reliability standards, covering service installations and upgrades, light replacements, customer service call centers and electric service reliability.

As part of the merger approval process in New Mexico, SPS agreed to:

- guarantee annual merger savings credits of approximately $780,000 and amortize merger costs through December 2004;
- share net non-fuel operating and maintenance savings equally among retail customers and shareholders;
- retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and
- not pass along any negative rate impacts of the merger.

PSCo Performance-Based Regulatory Plan The Colorado Public Utilities Commission (CPUC) established an electric PBRP under which PSCo operates. The major components of this regulatory plan include:

- an annual electric earnings test with the sharing between customers and shareholders of earnings in excess of the following limits:
  - all earnings above 10.5-percent return on equity for 2002;
  - no earnings sharing for 2003; and
  - an annual electric earnings test with the sharing of earnings in excess of the return on equity set in the 2002 rate case for 2004 through 2006;
- an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2006;
- a natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service through 2007; and
- an ICA that provides for the sharing of energy costs and savings relative to an annual baseline cost per kilowatt-hour generated or purchased. According to the terms of the merger rate agreement in Colorado, the annual baseline cost will be reset in 2002, based on a 2001 test year. Pursuant to a stipulation approved by the CPUC, the ICA remains in effect through March 31, 2005, to recover allowed ICA costs from 2001 and 2002. The recovery of fuel and purchased energy expense that began Jan. 1, 2003, will be decided in the PSCo 2002 general rate case. In the interim period until the conclusion of the general rate case, 2003 fuel and purchased energy expense is recovered through the interim adjustment clause (IAC).

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the earnings test. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually. During 2002, PSCo filed that its electric department earnings were below the 11-percent return-on-equity threshold. PSCo has estimated no customer refund obligation for 2002 under the earnings test, the electric QSP or the natural gas QSP. PSCo has estimated no customer refund obligation for 2001 under the earnings test. The 2001 earnings test filing has not been approved. A hearing is scheduled for May 2003.

PSCo 2002 General Rate Case In May 2002, PSCo filed a combined general retail electric, natural gas and thermal energy base rate case with the CPUC to address increased costs for providing services to Colorado customers. This filing was required as part of the Xcel Energy merger stipulation and agreement previously approved by the CPUC. Among other things, the case includes establishing an electric energy recovery mechanism, elimination of the qualifying facilities capacity cost adjustment (QFCCA), new depreciation rates and recovery of additional plant investment. PSCo requested an increase to its authorized rate of return on equity to 12 percent for electricity and 12.25 percent for natural gas. In early 2003, PSCo filed its rebuttal testimony in this rate case. At this point in the rate proceeding, PSCo is now requesting an overall annual increase to electric revenue of approximately $233 million. This is based on a $186-million increase for fuel and purchased energy expense and a $47-million electric base rate increase. PSCo is requesting an annual base rate decrease in natural gas revenue of approximately $21 million. The rebuttal case incorporates several adjustments to the original filing, including lower depreciation expense, higher fuel and energy expense and various corrections to the original filing.

Intervenors, including the CPUC staff and the Colorado Office of Consumer Council (OCC), have filed testimony requesting both electric and natural gas base rate decreases and increases in fuel and energy revenues that are less than the amounts requested by PSCo. On Feb. 19, 2003, the CPUC postponed the scheduled hearings for 30 days to allow parties to pursue a comprehensive settlement of all issues in this proceeding. PSCo filed a joint motion on March 14, 2003, extending the filing date of the settlement agreement until April 1, 2003. New rates are expected to be effective during the second quarter of 2003. A final decision on the recovery of fuel and energy costs will be applied retroactive to Jan. 1, 2003. Until such time, PSCo is billing customers under the IAC, assuming 100-percent pass-through cost recovery.

Tax Matters As discussed further in Note 18, the Internal Revenue Service (IRS) issued a Notice of Proposed Adjustment proposing to disallow interest expense deductions taken in tax years 1993 through 1997 related to corporate-owned life insurance (COLI) policy loans of PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo. Late in 2001, Xcel Energy received a technical advice memorandum from the IRS national office, which communicated a position adverse to PSRI. Consequently, the IRS examination division has disallowed the interest expense deductions for the tax years 1993 through 1997. After consultation with tax counsel, it is Xcel Energy's position that the tax law does not support the IRS determination. Although the ultimate resolution of this matter is uncertain, management continues to believe it will successfully resolve this matter without a material adverse impact on Xcel Energy's results of operations. However, defense of PSCo's position may require significant cash outlays on a temporary basis, if refund litigation is pursued in U.S. District Court.

The total disallowance of interest expense deductions for the period of 1993 through 1997 is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2002, would reduce earnings by an estimated $214 million, after tax. If COLI interest expense deductions were no longer available, annual earnings for 2003 would be reduced by an estimated $33 million, after tax, prospectively, which represents 8 cents per share using 2003 share levels.

Environmental Matters Our environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and wastes, remediation of contaminated sites and monitoring of discharges to the environment. A trend of greater environmental awareness and increasingly stringent regulation has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance.

In addition to nuclear decommissioning and spent nuclear fuel disposal expenses, costs charged to our operating expenses for environmental monitoring and disposal of hazardous materials and wastes were approximately:

- $149 million in 2002
- $146 million in 2001
- $144 million in 2000

We expect to expense an average of approximately $177 million per year from 2003 through 2007 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

Capital expenditures on environmental improvements at our regulated facilities, which include the cost of constructing spent nuclear fuel storage casks, were approximately:

- $108 million in 2002
- $136 million in 2001
- $57 million in 2000

Our regulated utilities expect to incur approximately $44 million in capital expenditures for compliance with environmental regulations in 2003 and approximately $948 million during the period from 2003 through 2007. Most of the costs are related to modifications to reduce the emissions of NSP-Minnesota's generating plants located in the Minneapolis-St. Paul metropolitan area. See Notes 18 and 19 to the Consolidated Financial Statements for further discussion of our environmental contingencies.

NRG expects to incur as much as $145 million in capital expenditures over the next five years to address conditions that existed when it acquired facilities, and to comply with new regulations.

Impact of Other Nonregulated Investments Xcel Energy's investments in nonregulated operations have had a significant impact on its results of operations. Xcel Energy does not expect to continue investing in nonregulated domestic and international power production projects through NRG, but may continue investing in natural gas marketing and trading through e prime and construction projects through Utility Engineering. Xcel Energy's nonregulated businesses may carry a higher level of risk than its traditional utility businesses due to a number of factors, including:

- competition, operating risks, dependence on certain suppliers and customers, and domestic and foreign environmental and energy regulations;
- partnership and government actions and foreign government, political, economic and currency risks; and
- development risks, including uncertainties prior to final legal closing.

Xcel Energy's earnings from nonregulated subsidiaries, other than NRG, also include investments in international projects, primarily in Argentina, through Xcel Energy International, and broadband communications systems through Seren. Management currently intends to hold and operate these investments, but is evaluating their strategic fit in Xcel Energy's business portfolio. As of Dec. 31, 2002, Xcel Energy's investment in Seren was approximately $255 million. Seren had capitalized $290 million for plant in service and had incurred another $21 million for construction work in progress for these systems at Dec. 31, 2002. Xcel Energy International's gross investment in Argentina, excluding unrealized currency translation losses of approximately $62 million, was $112 million at Dec. 31, 2002. Given the political and economic climate in Argentina, Xcel Energy continues to closely monitor the investment for asset impairment. Currently, management believes that no impairment exists in addition to what was recognized in 2002, as previously discussed.

Some of Xcel Energy's nonregulated subsidiaries have project investments, as listed in Note 14 to the Consolidated Financial Statements, consisting of minority interests, which may limit the financial risk, but also limit the ability to control the development or operation of the projects. In addition, significant expenses may be incurred for projects pursued by Xcel Energy's subsidiaries that do not materialize. The aggregate effect of these factors creates the potential for volatility in the nonregulated component of Xcel Energy's earnings. Accordingly, the historical operating results of Xcel Energy's nonregulated businesses may not necessarily be indicative of future operating results.

Inflation Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. Since late 2001, the Argentine peso has been significantly devalued due to the inflationary Argentine economy. Xcel Energy will continue to experience related currency translation adjustments through Xcel Energy International.

PENDING ACCOUNTING CHANGES

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 – "Accounting for Asset Retirement Obligations." This statement will require Xcel Energy to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset's life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires that a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation" are met.

Xcel Energy currently follows industry practice by ratably accruing the costs for decommissioning over the approved cost-recovery period and including the accruals in accumulated depreciation. At Dec. 31, 2002, Xcel Energy recorded and recovered in rates $662 million of decommissioning obligations and had estimated discounted decommissioning cost obligations of $1.1 billion based on approvals from the various state commissions, which used a single scenario. However, with the adoption of SFAS No. 143, a probabilistic view of several decommissioning scenarios was used, resulting in an estimated discounted decommissioning cost obligation of $1.6 billion.

Xcel Energy expects to adopt SFAS No. 143 as required on Jan. 1, 2003. In current estimates for adoption, the initial value of the liability, including cumulative accretion expense through that date, would be approximately $869 million. This liability would be established by reclassifying accumulated depreciation of $573 million and by recording two long-term assets totaling $296 million. A gross capitalized asset of $130 million would be recorded and would be offset by accumulated depreciation of $89 million. In addition, a regulatory asset of approximately $166 million would be recorded for the cumulative effect adjustment related to unrecognized depreciation and accretion under the new standard. Management expects that the entire transition amount would be recoverable in rates over time and, therefore, would support this regulatory asset upon adoption of SFAS No. 143.

Xcel Energy has completed a detailed assessment of the specific applicability and implications of SFAS No. 143 for obligations other than nuclear decommissioning. Other assets that may have potential asset retirement obligations include ash ponds, any generating plant with a Part 30 license and electric and natural gas transmission and distribution assets on property under easement agreements. Easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The liability is not estimable because Xcel Energy intends to utilize these properties indefinitely. The asset retirement obligations for the ash ponds and generating plants cannot be reasonably estimated due to an indeterminate life for the assets associated with the ponds and uncertain retirement dates for the generating plants. Since the time period for retirement is unknown, no liability would be recorded. When a retirement date is certain, a liability will be recorded.

SFAS No. 143 also will affect Xcel Energy's accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a GAAP liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates over time, Xcel Energy has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, Xcel Energy has an estimated regulatory liability accrued in accumulated depreciation for future removal costs of the following amounts at Dec. 31:

(Millions of dollars)	***2002***
NSP-Minnesota	$304
NSP-Wisconsin	70
PSCo	329
SPS	97
Cheyenne	9
Total Xcel Energy	$ 809

SFAS No. 145 In April 2002, the FASB issued SFAS No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," which supercedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things. Adoption of SFAS No. 145 may affect the recognition of impacts from NRG's financial improvement and restructuring plan, if existing debt agreements are ultimately renegotiated while NRG is still a consolidated subsidiary of Xcel Energy. Other impacts of SFAS No. 145 are not expected to be material to Xcel Energy.

SFAS No. 146 In June 2002, the FASB issued SFAS No. 146 – "Accounting for Exit or Disposal Activities," addressing recognition, measurement and reporting of costs associated with exit and disposal activities, including restructuring activities. SFAS No. 146 may have an impact on the timing of recognition of costs related to the implementation of the NRG financial improvement and restructuring plan; however, such impact is not expected to be material.

SFAS No. 148 In December 2002, the FASB issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure," amending FASB Statement No. 123 to provide alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation, and requiring disclosure in both annual and interim Consolidated Financial Statements about the method used and the effect of the method used on results. Xcel Energy continues to account for its stock-based compensation plans under Accounting Principles Board (APB) Opinion No. 25 - "Accounting for Stock Issued to Employees" and does not plan at this time to adopt the voluntary provisions of SFAS No. 148.

Emerging Issues Tax Force (EITF) Nos. 02-03 and 98-10 See Note 1 to the Consolidated Financial Statements regarding reporting changes made in 2002 for the presentation of trading results and pending changes related to accounting for the impacts of trading operations in 2003.

FASB Interpretation No. 45 (FIN No. 45) In November 2002, the FASB issued FIN No. 45 – "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after Dec. 31, 2002, irrespective of the guarantor's fiscal year-end. The disclosure requirements are effective for financial statements of interim or annual periods ending after Dec. 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46, requiring an enterprise's consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise's consolidated financial statements do not include the consolidations of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46, the voting interest approach is not effective in identifying controlling financial interest. As a result, Xcel Energy expects that it will have to consolidate its affordable housing investments made through Eloigne, which currently are accounted for under the equity method.

As of Dec. 31, 2002, the assets of these entities were approximately $155 million and long-term liabilities were approximately $87 million. Currently, investments of $62 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2002, Consolidated Balance Sheet. FIN No. 46 requires that for entities to be consolidated, the entities' assets be initially recorded at their carrying amounts at the date the new requirement first applies. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to the Xcel Energy's balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative-effect adjustment of an accounting change. Had Xcel Energy adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. Xcel Energy plans to adopt FIN No. 46 when required in the third quarter of 2003.

DERIVATIVES, RISK MANAGEMENT AND MARKET RISK

Business and Operational Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation, retail distribution and energy trading operations. In certain jurisdictions, purchased energy expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, Xcel Energy and its subsidiaries have limited exposure to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, electric energy and natural gas expenses are recovered based on fixed price limits or under established sharing mechanisms.

Xcel Energy manages commodity price risk by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil, and derivative instruments. Xcel Energy's risk management policy allows the company to manage the market price risk within each rate-regulated operation to the extent such exposure exists. Management is limited under the policy to enter into only transactions that manage market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas and electricity we provide to our retail customers even though the regulatory jurisdiction may provide dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments and physical contracts is done consistently with the local jurisdictional cost recovery mechanism.

Xcel Energy and its subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. Xcel Energy manages this market price risk by entering into firm power sales agreements for approximately 55 to 75 percent of its electric capacity and energy from each generation facility, using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed-priced electric energy requirements. Xcel Energy's risk management policy allows the company to manage market price risks, and provides guidelines for the level of price risk exposure that is acceptable within the company's operations.

Xcel Energy is exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from the company's equity method investments that own electric operations. Xcel Energy manages this market price risk through involvement with the management committee or board of directors of each of these ventures. Xcel Energy's risk management policy does not cover the activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk Xcel Energy and its subsidiaries are exposed to fluctuations in interest rates when entering into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to the volatility of cash flows for interest and result in primarily fixed-rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy's risk management policy allows the company to reduce interest rate exposure from variable-rate debt obligations.

At Dec. 31, 2002 and 2001, a 100-basis point change in the benchmark rate on Xcel Energy's variable debt would impact net income by approximately $52.2 million and $29.9 million, respectively. See Note 16 to the Consolidated Financial Statements for a discussion of Xcel Energy and its subsidiaries' interest rate swaps.

Currency Exchange Risk Xcel Energy and its subsidiaries have certain investments in foreign countries, creating exposure to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. Xcel Energy manages exposure to changes in foreign currency by entering into derivative instruments as determined by management. Xcel Energy's risk management policy provides for this risk management activity.

As discussed in Note 21 to the Consolidated Financial Statements, Xcel Energy has substantial investments in foreign projects, through NRG and other subsidiaries, creating exposure to currency translation risk. Cumulative translation adjustments, included in the Consolidated Statement of Stockholders' Equity as Accumulated Other Comprehensive Income, experienced to date have been material and may continue to occur at levels significant to the company's financial position. As of Dec. 31, 2002, NRG had two foreign currency exchange contracts with notional amounts of $3 million. If the contracts had been discontinued on Dec. 31, 2002, NRG would have owed the counterparties approximately $0.3 million.

Trading Risk Xcel Energy and its subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Xcel Energy's risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by the company's risk management committee, which is made up of management personnel not involved in the trading operations.

The fair value of Xcel Energy's trading contracts as of Dec. 31, 2002, is as follows:

(Millions of dollars)	*Total Fair Value*
Fair value of trading contracts outstanding at Jan. 1, 2002	$ 90.1
Contracts realized or settled during 2002	(139.5)
Fair value of trading contract additions and changes during the year	87.8
Fair value of contracts outstanding at Dec. 31, 2002*	$ 38.4

** Amounts do not include the impact of ratepayer sharing in Colorado.*

The future maturities of Xcel Energy's trading contracts are as follows:

(Millions of dollars) *Source of fair value*	*Maturity Less than 1 Year*	*Maturity 1 to 3 Years*	*Maturity 4 to 5 Years*	*Maturity Greater than 5 Years*	*Total Fair Value*
Prices actively quoted	$12.7	$ (7.1)	$ –	$ (1.9)	$ 3.7
Prices based on models and other valuation methods (including prices quoted from external sources)	$61.7	$52.6	$(23.0)	$(56.6)	$34.7

Xcel Energy's trading operations and power marketing activities measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movement, lognormal price distribution assumption and various holding periods varying from two to five days.

As of Dec. 31, 2002, the calculated VaRs were:

(Millions of dollars)	***Year Ended Dec. 31, 2002***	*Average*	***During 2002*** *High*	*Low*
Electric commodity trading	**0.29**	**0.62**	**3.39**	**0.01**
Natural gas commodity trading	**0.11**	**0.35**	**1.09**	**0.09**
Natural gas retail marketing	**0.54**	**0.47**	**0.92**	**0.32**
NRG power marketing *(a)*	**118.60**	**76.20**	**124.40**	**42.00**

(a) NRG VaR is an undiversified VaR.

As of Dec. 31, 2001, the calculated VaRs were:

(Millions of dollars)	*Year Ended Dec. 31, 2001*	*Average*	*During 2001 High*	*Low*
Electric commodity trading	0.52	1.71	7.37	0.16
Natural gas commodity trading	0.16	0.15	0.52	0.01
Natural gas retail marketing	0.69	0.39	0.94	0.13
NRG power marketing	71.70	78.80	126.60	58.60

In 2001, Xcel Energy changed its holding period for measuring VaR from electricity trading activity from 21 days to two to five days. Xcel Energy's revised holding periods are generally consistent with current industry standard practice.

Credit Risk In addition to the risks discussed previously, Xcel Energy and its subsidiaries are exposed to credit risk in the company's risk management activities. Credit risk relates to the risk of loss resulting from the nonperformance by a counterparty of its contractual obligations. As Xcel Energy continues to expand its natural gas and power marketing and trading activities, exposure to credit risk and counterparty default may increase. Xcel Energy and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

Xcel Energy and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

(Millions of dollars)	***2002***	*2001*	*2000*
Net cash provided by operating activities	**$1,715**	$1,584	$1,408

Cash provided by operating activities increased during 2002, compared with 2001, primarily due to NRG's efforts to conserve cash by deferring the payment of interest payments and managing its cash flows more closely. NRG's accrued interest costs rose by nearly $200 million in 2002, compared with year-end 2001 levels. In addition, regulated utility operating cash flows increased in 2002 due to lower 2002 receivables and unbilled revenues, reflecting collections of higher year-end 2001 amounts. Cash provided by operating activities increased during 2001, compared with 2000, primarily due to higher net income, depreciation and improved working capital.

(Millions of dollars)	***2002***	*2001*	*2000*
Net cash used in investing activities	**$(2,718)**	$(5,168)	$(3,347)

Cash used in investing activities decreased during 2002, compared with 2001, primarily due to lower levels of nonregulated capital expenditures as a result of NRG terminating its acquisition program due to its financial difficulties. Such nonregulated expenditures decreased $2.8 billion in 2002 due mainly to NRG asset acquisitions in 2001 that did not recur in 2002. Cash used in investing activities increased during 2001, compared with 2000, primarily due to increased levels of nonregulated capital expenditures and asset acquisitions, primarily at NRG. The increase was partially offset by Xcel Energy's sale of most of its investment in Yorkshire Power.

(Millions of dollars)	***2002***	*2001*	*2000*
Net cash provided by financing activities	**$ 1,580**	$ 3,713	$ 2,016

Cash provided by financing activities decreased during 2002, compared with 2001, primarily due to lower NRG capital requirements and constraints on NRG's ability to access the capital market due to its financial difficulties, as discussed previously. NRG's cash provided from financing activities declined by $2.7 billion in 2002, compared with 2001. Cash provided by financing activities increased during 2001, compared with 2000, primarily due to increased short-term borrowings and net long-term debt issuances, mainly to fund NRG acquisitions.

See discussion of trends, commitments and uncertainties with the potential for future impact on cash flow and liquidity under Capital Sources.

CAPITAL REQUIREMENTS

Utility Capital Expenditures, Nonregulated Investments and Long-Term Debt Obligations The estimated cost of the capital expenditure programs of Xcel Energy and its subsidiaries, excluding NRG, and other capital requirements for the years 2003, 2004 and 2005 are shown in the table below.

(Millions of dollars)	*2003*	*2004*	*2005*
Electric utility	$ 700	$ 840	$ 950
Natural gas utility	110	110	110
Common utility	90	50	40
Total utility	900	1,000	1,100
Other nonregulated (excluding NRG)	32	23	15
Total capital expenditures	932	1,023	1,115
Sinking funds and debt maturities	563	169	223
Total capital requirements	$ 1,495	$ 1,192	$ 1,338

The capital expenditure forecast for 2004 includes new steam generators at the Prairie Island nuclear plant. These expenditures will not occur unless the Minnesota Legislature grants additional spent fuel storage at Prairie Island during 2003. The capital expenditure forecast also includes the early stages of the costs related to modifications to reduce the emissions of NSP-Minnesota's generating plants located in the Minneapolis and St. Paul metropolitan area. This project is expected to cost approximately $1.1 billion with major construction starting in 2005 and finishing in 2009.

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. For more information, see Notes 4 and 18 to the Consolidated Financial Statements.

Xcel Energy's investment in exempt wholesale generators and foreign utility companies, which includes NRG and other Xcel Energy subsidiaries, is currently limited to 100 percent of consolidated retained earnings, as a result of the PUHCA restrictions. At Dec. 31, 2002, such investments exceeded consolidated retained earnings.

NRG Energy is required to provide financial guarantees of up to approximately $8 million for closure and ongoing monitoring costs of some sites to which it sends coal ash and other waste, by April 30, 2003.

NRG Capital Expenditures Management expects NRG's capital expenditures, which include refurbishments and environmental compliance, to total approximately $475 million to $525 million in the years 2003 through 2007. NRG anticipates funding its ongoing capital requirements through committed debt facilities, operating cash flows and existing cash. NRG's capital expenditure program is subject to continuing review and modification. The timing and actual amount of expenditures may differ significantly based upon plant operating history, unexpected plant outages, changes in the regulatory environment and the availability of cash. The pending financial restructuring or bankruptcy filings of NRG may affect the timing and magnitude of capital resources available to NRG and, accordingly, the level of capital expenditures NRG can fund.

Contractual Obligations and Other Commitments Xcel Energy has a variety of contractual obligations and other commercial commitments that represent prospective requirements in addition to its capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in the Consolidated Statements of Capitalization and Notes 5, 6, 7, 16 and 18 to the Consolidated Financial Statements.

(Thousands of dollars)		*Payments Due by Period*			
Contractual obligations	*Total*	*Less than 1 Year*	*1–3 Years*	*4–5 Years*	*After 5 Years*
Long-term debt	$14,311,689	$ 7,756,903	$ 547,796	$1,137,934	$ 4,869,056
Capital lease obligations	688,421	34,422	67,771	66,386	519,842
Operating leases*(a)*	386,215	66,155	125,031	108,534	86,495
Unconditional purchase obligations	11,240,364	1,317,293	2,214,974	1,817,770	5,890,327
Other long-term obligations	699,248	42,597	64,517	34,594	557,540
Short-term debt	1,541,963	1,541,963	–	–	–
Total contractual cash obligations	$28,867,900	$10,759,333	$3,020,089	$3,165,218	$11,923,260

(a) Under some leases, we would have to sell or purchase the property that we lease if we chose to terminate before the scheduled lease expiration date. Most of our railcar, vehicle and equipment, and aircraft leases have these terms. We would then own the equipment and could continue to use it in the normal course of business or sell it. At Dec. 31, 2002, the amount that we would have to pay if we chose to terminate these leases was approximately $160 million.

Common Stock Dividends Future dividend levels will be dependent upon the statutory limitations discussed further, as well as Xcel Energy's results of operations, financial position, cash flows and other factors, and will be evaluated by the Xcel Energy board of directors.

Under the PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of Xcel Energy were a deficit of $101 million at Dec. 31, 2002. Xcel Energy did not declare a dividend on its common stock during the first quarter of 2003. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until Sept. 30, 2003. It is not known when or if the SEC will act on this request. As explained below, Xcel Energy has reached a preliminary settlement agreement with the various NRG creditors. Also, Xcel Energy could be required to cease including NRG as a consolidated subsidiary for financial reporting purposes, if NRG were to seek protection under the bankruptcy laws and Xcel Energy ceased to have control over NRG. In the event the tentative settlement is effectuated and Xcel Energy is required to cease including NRG as a consolidated subsidiary in its financial statements, the financial impact of these events are expected to positively impact retained earnings and may be sufficient to eliminate the negative retained earnings balance, absent additional charges at NRG. Xcel Energy cannot predict the precise financial impact of these items at this time. For this reason, Xcel Energy will continue seeking authorization from the SEC so it is able to pay dividends notwithstanding negative retained earnings. Xcel Energy intends to make every effort to pay the full common stock dividend of 75 cents per share during 2003.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, i.e., not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at Dec. 31, 2002, was 85 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

CAPITAL SOURCES

Xcel Energy expects to meet future financing requirements by periodically issuing long-term debt, short-term debt, common stock and preferred securities to maintain desired capitalization ratios. As a result of its registration as a holding company under the PUHCA, Xcel Energy is required to maintain a common equity ratio of 30 percent or higher in its consolidated capital structure.

On Nov. 7, 2002, the SEC issued an order authorizing Xcel Energy to engage in certain financing transactions through March 31, 2003, so long as its common equity ratio, as reported in its most recent Form 10-K or Form 10-Q and as adjusted for pending subsequent items that affect capitalization, was at least 24 percent of its total capitalization. Financings of Xcel Energy authorized by the SEC included the issuance of debt, including convertible debt, to refinance or replace Xcel Energy's $400-million credit facility that expired on Nov. 8, 2002, issuance of $450 million of common stock, less any amounts issued as part of the refinancing of the $400-million credit facility, and the renewal of guarantees for various trading obligations of NRG's power marketing subsidiary. The SEC reserved authorizing additional securities issuances by Xcel Energy through June 30, 2003, while its common equity ratio is below 30 percent.

For this purpose, common equity, including minority interest, at Dec. 31, 2002, was 23 percent of total capitalization. As a result, Xcel Energy may experience constraints on available capital sources that may be affected by factors including earnings levels, project acquisitions and the financing actions of our subsidiaries. In the event that NRG were to seek protection under bankruptcy laws and Xcel Energy ceased to have control over NRG, NRG would no longer be a consolidated subsidiary of Xcel Energy for financial reporting purposes, and Xcel Energy's common equity ratio under the SEC's method of calculation would exceed 30 percent.

In December 2002, Xcel Energy filed a request for additional financing authorization with the SEC. Xcel Energy requested an increase from $2 billion to $2.5 billion in the aggregate amount of securities that it may issue during the period through Sept. 30, 2003. In addition, the request proposed that common equity will be at least 30 percent of total consolidated capitalization, provided that in any event the 30-percent common equity requirement is not met, Xcel Energy may issue common stock. The notice period expired with no comments. SEC action on the request is pending. As a result, Xcel Energy at the present time cannot finance, either on a short-term or long-term basis, without SEC approval unless its common equity is at least 30 percent of total capitalization.

With approval of the request currently pending before the SEC, further described below, management believes it will have adequate authority under SEC orders and regulations to conduct business as proposed during 2003 and will seek additional authorization when necessary.

Short-Term Funding Sources Historically, Xcel Energy has used a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for utility construction expenditures and nonregulated project investments. Another significant short-term funding need is the dividend payment requirement, as discussed previously in Common Stock Dividends.

Operating cash flow as a source of short-term funding is reasonably likely to be affected by such operating factors as weather; regulatory requirements, including rate recovery of costs, environmental regulation compliance and industry deregulation; changes in the trends for energy prices and supply; and operational uncertainties that are difficult to predict. See further discussion of such factors under Statement of Operations Analysis and Factors Affecting Results of Operations.

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. These factors are evaluated by credit-rating agencies that review Xcel Energy and its subsidiary operations on an ongoing basis. NRG's credit situation has affected Xcel Energy's credit ratings and access to short-term funding. As a result of a decline in its credit ratings, Xcel Energy has been unable to utilize the commercial paper market to satisfy any short-term funding needs. For additional information on Xcel Energy's short-term borrowing arrangements, see Note 5 to the Consolidated Financial Statements.

Access to reasonably priced capital markets is also dependent in part on credit agency reviews. In the past year, our credit ratings and those of our subsidiaries have been adversely affected by NRG's credit contingencies, despite what management believes is a reasonable separation of NRG's operations and credit risk from our utility operations and corporate financing activities. These ratings reflect the views of Moody's and Standard & Poor's. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating company. As of Feb. 10, 2003, the following represents the credit ratings assigned to various Xcel Energy companies:

Company	*Credit Type*	*Moody's**	*Standard & Poor's*
Xcel Energy	Senior Unsecured Debt	Baa3	BBB-
Xcel Energy	Commercial Paper	NP	A3
NSP-Minnesota	Senior Unsecured Debt	Baa1	BBB-
NSP-Minnesota	Senior Secured Debt	A3	BBB+
NSP-Minnesota	Commercial Paper	P2	A3
NSP-Wisconsin	Senior Unsecured Debt	Baa1	BBB
NSP-Wisconsin	Senior Secured Debt	A3	BBB+
PSCo	Senior Unsecured Debt	Baa2	BBB-
PSCo	Senior Secured Debt	Baa1	BBB+
PSCo	Commercial Paper	P2	A3
SPS	Senior Unsecured Debt	Baa1	BBB
SPS	Commercial Paper	P2	A3
NRG	Corporate Credit Rating	Caa3**	D**

* *Negative credit watch/negative outlook*
** *Below investment grade*

NRG's access to short-term capital is currently nonexistent outside of bankruptcy. The downgrade of NRG's credit ratings below investment grade in July 2002 has resulted in cash collateral requirements, as discussed previously and in Notes 4 and 7 to the Consolidated Financial Statements. In addition, lower credit ratings will increase the relative cost of NRG's capital financing compared with historical levels, assuming NRG could obtain such financing.

In June 2002, Xcel Energy's access to commercial paper markets was reduced due to lowered credit ratings, shown previously. Xcel Energy typically uses sources of financing, both short- and long-term, other than commercial paper to fulfill its cash needs and manage its capital structure.

NRG Capital Sources NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its project's cash flows, which are typically secured by the plant's physical assets and equity interests in the project company. As discussed previously, NRG's credit situation has significantly affected its credit ratings and virtually eliminated its access to short-term funding. See credit ratings in previous table. NRG anticipates funding its ongoing capital requirements through committed debt facilities, operating cash flows and existing cash.

NRG's operating cash flows have been affected by lower operating margins as a result of low power prices since mid-2001. Seasonal variations in demand and market volatility in prices are not unusual in the independent power sector, and NRG normally experiences higher margins in peak summer periods and lower margins in non-peak periods. NRG also has incurred significant amounts of debt to finance its acquisitions in the past several years, and the servicing of interest and principal repayments from such financing is largely dependent on domestic project cash flows. Management has concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations at NRG.

Substantially all of NRG's operations are conducted by project subsidiaries and project affiliates. NRG's cash flow and ability to service corporate-level indebtedness when due is dependent upon receipt of cash dividends and distributions or other transfers from NRG's projects and other subsidiaries. NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its project's cash flows, which are typically secured by the plant's physical assets and equity interests in the project company. In August 2002, NRG suspended substantially all of its acquisition and development activities indefinitely, pending a comprehensive restructuring of NRG. The debt agreements of NRG's subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of Dec. 31, 2002, Loy Yang, Energy Center Kladno, LSP Energy (Batesville), NRG South Central and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG. In addition, NRG's subsidiaries, including LSP Kendall, NRG McClain, NRG Mid-Atlantic, NRG South Central and NRG Northeast Generating are in default on their various debt instruments, resulting in dividend payment restrictions.

For additional information on NRG's defaults on short-term and long-term borrowing arrangements, see Note 7 to the Consolidated Financial Statements.

Registration Statements Xcel Energy's Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2002, Xcel Energy had approximately 399 million shares of common stock outstanding. In addition, Xcel Energy's Articles of Incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On Dec. 31, 2002, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Registered securities available for issuance are as follows:

In February 2002, Xcel Energy filed a $1-billion shelf registration with the SEC. Xcel Energy may issue debt securities, common stock and rights to purchase common stock under this shelf registration. Xcel Energy has approximately $482.5 million remaining under this registration, which it can issue only when its common equity exceeds 30 percent of its total capitalization absent SEC approval under PUHCA.

In April 2001, NSP-Minnesota filed a $600-million, long-term debt shelf registration with the SEC. NSP-Minnesota has approximately $415 million remaining under this registration.

PSCo has an effective shelf registration statement with the SEC under which $300 million of senior debt securities are available for issuance.

In June 2001, NRG filed a shelf registration with the SEC to sell up to $2 billion in debt securities, common and preferred stock, warrants and other securities. NRG has approximately $1.5 billion remaining under this shelf registration. However, NRG's access to capital markets is severely constrained and the registration no longer represents access to financing sources.

In March 2003, PSCo issued $250 million of 4.875-percent, First Collateral Trust Bonds due in 2013. The bonds were issued in a private placement to qualified institutional buyers and were not registered under the Securities Act of 1933. Pursuant to a registration rights agreement, PSCo has an obligation to file a registration statement for an exchange offer for these bonds.

OTHER LIQUIDITY AND CAPITAL RESOURCE CONSIDERATIONS

NRG Financial Issues and Potential Bankruptcy Historically, NRG has obtained cash from operations, issuance of debt and equity securities, borrowings under credit facilities, capital contributions from Xcel Energy, reimbursement by Xcel Energy of tax benefits pursuant to a tax-sharing agreement and proceeds from nonrecourse project financings. NRG has used these funds to finance operations; service debt obligations; fund the acquisition, development and construction of generation facilities; finance capital expenditures; and meet other cash and liquidity needs.

As discussed previously, substantially all of NRG's operations are conducted by project subsidiaries and project affiliates. NRG's cash flow and ability to service corporate-level indebtedness when due is dependent upon receipt of cash dividends and distributions or other transfers from NRG's projects and other subsidiaries. The debt agreements of NRG's subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of Dec. 31, 2002, Loy Yang, Killingholme, Energy Center Kladno, LSP Energy (Batesville), NRG South Central and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG.

Killingholme, NRG South Central and NRG Northeast Generating are in default on their credit agreements. NRG believes the situations at Energy Center Kladno, Loy Yang and Batesville do not create an event of default and will not allow the lenders to accelerate the project financings.

In all of these cases, NRG's corporate-level financial obligations to project lenders is limited to no more than six-months' debt service.

As discussed previously, NRG's operating cash flows have been affected by lower operating margins as a result of low power prices since mid-2001. Seasonal variations in demand and market volatility in prices are not unusual in the independent power sector, and NRG normally experiences higher margins in peak summer periods and lower margins in non-peak periods. NRG also has incurred significant amounts of debt to finance its acquisitions in the past several years, and the servicing of interest and principal repayments from such financing is largely dependent on domestic project cash flows. NRG's management has concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations.

Since mid-2002, as discussed previously, NRG has experienced severe financial difficulties, resulting primarily from declining credit ratings and lower prices for power. These financial difficulties have caused NRG to, among other things, miss several scheduled payments of interest and principal on its bonds and incur an approximately $3-billion asset impairment charge. The asset impairment charge relates to write-offs for anticipated losses on sales of several projects as well as anticipated losses for projects for which NRG has stopped funding. In addition, as a result of having its credit ratings downgraded, NRG is in default of obligations to post cash collateral of approximately $1 billion. Furthermore, on Nov. 6, 2002, lenders to NRG accelerated approximately $1.1 billion of NRG's debt under the construction revolver financing facility, rendering the debt immediately due and payable. In addition, on Feb. 27, 2003, lenders to NRG accelerated approximately $1.0 billion of NRG Energy's debt under the corporate revolver financing facility, rendering the debt immediately due and payable. NRG continues to work with its lenders and bondholders on a comprehensive restructuring plan. NRG does not contemplate making any principal or interest payments on its corporate-level debt pending the restructuring of its obligations. Consequently, NRG is, and expects to continue to be, in default under various debt instruments. By reason of these various defaults, the lenders are able to seek to enforce their remedies, if they so choose, and that would likely lead to a bankruptcy filing by NRG in 2003.

Whether NRG does or does not reach a consensual restructuring plan with its creditors, there is a substantial likelihood that NRG will be the subject of a bankruptcy proceeding in 2003. If an agreement is reached with NRG's creditors on a restructuring plan, it is expected that NRG would as soon as practicable commence a Chapter 11 bankruptcy case and immediately seek approval of a prenegotiated plan of reorganization. Absent an agreement with NRG's creditors and the continued forbearance by such creditors, NRG will be subject to substantial doubt as to its ability to continue as a going concern and will likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved and may involve claims against Xcel Energy under the equitable doctrine of substantive consolidation, as discussed following.

In addition to the collateral requirements, NRG must continue to meet its ongoing operational and construction funding requirements. Since NRG's credit-rating downgrade, its cost of borrowing has increased and it has not been able to access the capital markets. NRG believes that its current funding requirements under its already reduced construction program may be unsustainable given its inability to raise money in the capital markets and the uncertainties involved in obtaining additional equity funding from Xcel Energy. NRG and Xcel Energy have retained financial advisors to help work through these liquidity issues.

As discussed previously, NRG is not making any payments of principal or interest on its corporate-level debt, and neither NRG nor any subsidiary is making payment of principal or interest on publicly held bonds. This failure to pay, coupled with past and anticipated proceeds from the sales of projects, has provided NRG with adequate liquidity to meet its day-to-day operating costs. However, there can be no assurance that holders of NRG indebtedness, on which interest and principal are not being paid, will not seek to accelerate the payment of their indebtedness, which would likely lead to NRG seeking relief under the bankruptcy laws.

At the present time and based on conversations with various lenders, Xcel Energy management believes that the appropriate course is to seek a consensual restructuring of NRG with its creditors. Following an agreement on the restructuring with NRG's creditors, as described in Note 4 to the Consolidated Financial Statements, it is expected that NRG would commence a Chapter 11 bankruptcy proceeding and immediately seek approval of a prenegotiated plan of reorganization. If a consensual restructuring cannot be reached, the likelihood of NRG becoming subject to a protracted voluntary or involuntary bankruptcy proceeding is increased. If a consensual restructuring of NRG cannot be obtained and NRG remains outside of a bankruptcy proceeding, NRG is expected to continue selling assets to reduce its debt and improve its liquidity. Through Jan. 31, 2003, NRG completed a number of transactions, which resulted in net cash proceeds to NRG after debt pay-downs and after financial advisor fees of approximately $350 million.

Xcel Energy Impacts During 2002, Xcel Energy provided NRG with $500 million of cash infusions. In May 2002, Xcel Energy and NRG entered into a support and capital subscription agreement (Support Agreement) pursuant to which Xcel Energy agreed, under certain circumstances, to provide an additional $300 million to NRG. Xcel Energy has not, to date, provided funds to NRG under this agreement. See discussion of preliminary settlement with NRG's creditors at Note 4 to the Consolidated Financial Statements.

Many companies in the regulated utility industry, with which the independent power industry is closely linked, also are restructuring or reviewing their strategies. Several of these companies are discontinuing going forward with unregulated investments, seeking to divest of their unregulated subsidiaries or attempting to have their regulated subsidiaries acquire their unregulated subsidiaries. This may lead to an increased competition between the regulated utilities and the unregulated power producers within certain markets. In such instances, NRG may compete with regulated utilities in the influence of market designs and rulemaking.

On March 26, 2003, Xcel Energy's board of directors approved a tentative settlement with holders of most of NRG's long-term notes and the steering committee representing NRG's bank lenders regarding alleged claims of such creditors against Xcel Energy, including claims related to the Support Agreement. The settlement is subject to a variety of conditions as set forth below, including definitive documentation. As described in Note 4 to the Consolidated Financial Statements, the settlement would require Xcel Energy to pay up to $752 million over 13 months. Xcel Energy would expect to fund those payments with cash from tax savings. The principal terms of the settlement as of the date of this report were as follows:

Xcel Energy would pay up to $752 million to NRG to settle all claims of NRG and the claims of NRG against Xcel Energy, including all claims under the Support Agreement.

$350 million would be paid at or shortly following the consummation of a restructuring of NRG's debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on Jan. 1, 2004, and all or any part of such payment could be made, at Xcel Energy's election, in Xcel Energy common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that Xcel Energy had not received at such time tax refunds equal to $352 million associated with the loss on its investment in NRG. To the extent Xcel Energy had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of the Xcel Energy payments are contingent on receiving releases from NRG creditors. To the extent Xcel Energy does not receive a release from an NRG creditor, Xcel Energy's obligation to make $390 million of the payments would be reduced based on the amount of the creditor's claim against NRG. As noted below, however, the entire settlement is contingent upon Xcel Energy receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that Xcel Energy's payment obligations would be reduced by more than approximately $60 million. Any reduction would come from the Xcel Energy payment due on April 30, 2004.

Upon the consummation of NRG's debt restructuring through a bankruptcy proceeding, Xcel Energy's exposure on any guarantees or other credit supported obligations incurred by Xcel Energy for the benefit of NRG or any subsidiary would be terminated, and any cash collateral posted by Xcel Energy would be returned to it. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with Xcel Energy, any intercompany claims of Xcel Energy against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of Jan. 31, 2003, will be reduced from approximately $55 million as asserted by Xcel Energy to $13 million. The $13 million agreed amount is to be paid upon the consummation of NRG's debt restructuring with $3 million in cash and an unsecured promissory note of NRG on market terms in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with Xcel Energy or any of its other affiliates for tax purposes at any time after its June 2002 reaffiliation or treated as a party to or otherwise entitled to the benefits of any tax sharing agreement with Xcel Energy. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss Xcel Energy expects to incur in connection with the write-down of its investment in NRG.

Xcel Energy's obligations under the tentative settlement, including its obligations to make the payments set for the above, are contingent upon, among other things, the following:

- definitive documentation, in form and substance satisfactory to the parties;
- between 50 percent and 100 percent of the claims represented by various NRG facilities or creditor groups (NRG Credit Facilities) having executed an agreement, in form and substance satisfactory to Xcel Energy, to support the settlement;
- various stages of the implementation of the settlement occurring by dates currently being negotiated, with the consummation of the settlement to occur by Sept. 30, 2003;
- the receipt of releases in favor of Xcel Energy by at least 85 percent of the claims represented by the NRG Credit Facilities;
- the receipt by Xcel Energy of all necessary regulatory approvals; and
- no downgrade prior to consummation of the settlement of any Xcel Energy credit rating from the level of such rating as of March 25, 2003.

Based on the foreseeable effects of a settlement agreement with the major NRG noteholders and bank lenders and the tax effect of an expected write-off of Xcel Energy's investment in NRG, Xcel Energy would recognize the expected tax benefits of the write-off as of Dec. 31, 2002. The tax benefit has been estimated at approximately $706 million. This benefit is based on the tax basis of Xcel Energy's investment in NRG.

Xcel Energy expects to claim a worthless stock deduction in 2003 on its investment. This would result in Xcel Energy having a net operating loss for the year. Under current law, this 2003 net operating loss could be carried back two years for federal purposes. Xcel Energy expects to file for a tax refund of approximately $355 million in first quarter 2004. This refund is based on a two-year carryback. However, under the Bush administration's new dividend tax proposal, the carryback could be one year, which would reduce the refund to $125 million.

As to the remaining $351 million of expected tax benefits, Xcel Energy expects to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The amount of cash freed up by the reduction in estimated tax payments would depend on Xcel Energy's taxable income.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities, consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. In the event the settlement described previously is not effectuated, Xcel Energy believes that any effort to substantively consolidate Xcel Energy with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims, or other claims under piercing the corporate veil, alter ego or related theories, should an NRG bankruptcy proceeding commence, particularly in the absence of a prenegotiated plan of reorganization, and Xcel Energy cannot be certain how a bankruptcy court would resolve these issues. One of the creditors of the NRG project Pike, as discussed in Note 18 to the Consolidated Financial Statements, has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and Xcel Energy. Also, as discussed in Note 18 to the Consolidated Financial Statements, a group of former executives of NRG have commenced an involuntary bankruptcy proceeding against NRG related to the payments of certain benefits and deferred compensation amounts claimed to be due them. If a bankruptcy court were to allow substantive consolidation of Xcel Energy and NRG, it would have a material adverse effect on Xcel Energy.

The accompanying Consolidated Financial Statements do not reflect any conditions or matters that would arise if NRG were in bankruptcy.

If NRG were to file for bankruptcy, and the necessary actions were taken by Xcel Energy to fully relinquish its effective control over NRG, Xcel Energy anticipates that NRG would no longer be included in Xcel Energy's consolidated financial statements, prospectively from the date such actions were taken. Such de-consolidation of NRG would encompass a change in Xcel Energy's accounting for NRG to the equity method, under which Xcel Energy would continue to record its interest in NRG's income or losses until Xcel Energy's investment in NRG (under the equity method) reached the level of obligations that Xcel Energy had either guaranteed on behalf of NRG or was otherwise committed to in the form of financial assistance to NRG. Prior to completion of a bankruptcy proceeding, a prenegotiated plan of reorganization or other settlement reached with NRG's creditors would be the determining factors in assessing whether a commitment to provide financial assistance to NRG existed at the time of de-consolidation.

At Dec. 31, 2002, Xcel Energy's pro forma investment in NRG, calculated under the equity method if applied at that date, was a negative $625 million. If the amount of guarantees or other financial assistance committed to NRG by Xcel Energy exceeded that level after de-consolidation of NRG, then NRG's losses would continue to be included in Xcel Energy's results until the amount of negative investment in NRG reaches the amount of guarantees and financial assistance committed to by Xcel Energy. As of Dec. 31, 2002, the estimated guarantee exposure that Xcel Energy had related to NRG liabilities was $96 million, as discussed in Note 16 to the Consolidated Financial Statements, and potential financial assistance was committed in the form of a support and capital subscription agreement pursuant to which Xcel Energy agreed, under certain circumstances, to provide an additional $300 million contribution to NRG if the financial restructuring plan discussed earlier is approved by NRG's creditors. Additional commitments for financial assistance to NRG could be created in 2003 as Xcel Energy, NRG and NRG's creditors continue to negotiate terms of a possible prenegotiated plan of reorganization to resolve NRG's financial difficulties.

In addition to the effects of NRG's losses, Xcel Energy's operating results and retained earnings in 2003 could also be affected by the tax effects of any guarantees or financial commitments to NRG, if such income tax benefits were considered likely of realization in the foreseeable future. The income tax benefits recorded in 2002 related to Xcel Energy's investment in NRG, as discussed in Note 11 to the Consolidated Financial Statements, includes only the tax benefits related to cash and stock investments already made in NRG at Dec. 31, 2002. Additional tax benefits could be recorded in 2003 at the time that such benefits are considered likely of realization, when the payment of guarantees and other financial assistance to NRG become probable.

As noted previously, a bankruptcy filing by NRG would have several effects on Xcel Energy's financial condition and results of operations. If a bankruptcy filing and other necessary governance actions eliminate Xcel Energy's control over NRG, then management anticipates that NRG would no longer be included in Xcel Energy's consolidated financial statements, prospectively from the date such actions were taken. Such de-consolidation of NRG would encompass a change in Xcel Energy's accounting for NRG to the equity method, thus all of NRG's assets and liabilities would be presented in a single line on Xcel Energy's balance sheet at that point. This would reduce Xcel Energy's debt leverage ratios and increase its equity ratio as a percent of total capitalization to above 30 percent, thereby reinstating its financing authority under PUHCA. In addition, the revenues and expenses of NRG would be reported on a net basis as equity income or losses. Losses would be subject to certain limitations. Also, the operating, investing and financing cash flows of NRG would not be included in Xcel Energy's except to the extent cash flowed between Xcel Energy and NRG. Finally, there may be tax effects for guarantees or financial commitments made by Xcel Energy to NRG related to the bankruptcy or other resolution of NRG's financial difficulties. See Note 4 to the Consolidated Financial Statements for further discussion of these possible effects of an NRG bankruptcy filing on Xcel Energy.

Xcel Energy believes that the ultimate resolution of NRG's financial difficulties and going-concern uncertainty will not affect Xcel Energy's ability to continue as a going concern. Xcel Energy is not dependent on cash flows from NRG, nor is Xcel Energy contingently liable to creditors of NRG in an amount material to Xcel Energy's liquidity. Xcel Energy believes that its cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund its non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, Xcel Energy believes it will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG's financial restructuring plan.

INDEPENDENT AUDITORS' REPORT

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of operations, common stockholders' equity and other comprehensive income and cash flows for the three years ended December 31, 2002. These consolidated 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 balance sheet of NRG Energy, Inc. (a wholly owned subsidiary of Xcel Energy Inc.) for the years ended December 31, 2002 and 2001, or the consolidated statements of operations, stockholder's (deficit)/equity and cash flows for the three years ended December 31, 2002 included in the consolidated financial statements of the Company, which statements reflect total assets and revenues of 40% and 24% for 2002, respectively, and total assets and revenues of 45% and 21% for 2001, respectively, and revenues of 20% for 2000, of the related consolidated totals. Those statements were audited by other auditors whose report has been furnished to us (which as to 2002 expresses an unqualified opinion and includes an explanatory paragraph describing conditions that raise substantial doubt about NRG Energy, Inc.'s ability to continue as a going concern and emphasis of a matter paragraphs related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002 and the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001), and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. for the periods described above, is based solely on the report of the other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2002 and 2001 and the results of their operations and their cash flows for each of the three years ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 17 to the consolidated financial statements, effective January 1, 2001, Xcel Energy Inc. and subsidiaries adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, Xcel Energy Inc. and subsidiaries adopted SFAS No. 142, "Goodwill and Other Intangible Assets," and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

Note 4 to the consolidated financial statements discusses the implications to the Company related to credit and liquidity constraints, various defaults under credit arrangements and a likely Chapter 11 bankruptcy protection filing at NRG Energy, Inc.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
March 28, 2003

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder's (deficit)/equity present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 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 audits. We conducted our audits 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 our audits provide a reasonable basis for our opinion.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company is experiencing credit and liquidity constraints and has various credit arrangements that are in default. As a direct consequence, during 2002 the Company entered into discussions with its creditors to develop a comprehensive restructuring plan. In connection with its restructuring efforts, it is likely the Company and certain of its subsidiaries will file for Chapter 11 bankruptcy protection. These conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 19 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," for the year ended December 31, 2002. As discussed in Note 26 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," on January 1, 2001. As discussed in Notes 3 and 5 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," on January 1, 2002.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
March 28, 2003

(Thousands of dollars, except per share data)	Year ended Dec. 31 2002	2001	2000
OPERATING REVENUES			
Electric utility	**$ 5,435,377**	$6,394,737	$5,674,485
Natural gas utility	**1,397,800**	2,052,651	1,468,880
Electric and natural gas trading margin	**8,485**	89,249	41,357
Nonregulated and other	**2,611,149**	2,579,715	1,856,030
Equity earnings from investments in affiliates	**71,561**	217,070	182,714
Total operating revenues	**9,524,372**	11,333,422	9,223,466
OPERATING EXPENSES			
Electric fuel and purchased power – utility	**2,199,099**	3,171,660	2,580,723
Cost of natural gas sold and transported – utility	**851,987**	1,517,557	948,145
Cost of sales – nonregulated and other	**1,361,466**	1,318,586	876,698
Other operating and maintenance expenses – utility	**1,501,602**	1,506,039	1,446,122
Other operating and maintenance expenses – nonregulated	**787,968**	676,408	533,379
Depreciation and amortization	**1,037,429**	906,303	766,746
Taxes (other than income taxes)	**318,641**	316,492	351,412
Write-downs and disposal losses from investments (see Notes 2 and 3)	**207,290**	–	–
Special charges (see Note 2)	**2,691,223**	62,230	241,042
Total operating expenses	**10,956,705**	9,475,275	7,744,267
Operating income (loss)	**(1,432,333)**	1,858,147	1,479,199
Interest income	**45,863**	43,548	27,480
Other nonoperating income	**28,167**	17,961	5,094
Other nonoperating expense	**(30,043)**	(15,623)	(15,994)
INTEREST CHARGES AND FINANCING COSTS			
Interest charges – net of amounts capitalized (includes other financing costs of $59,724, $21,058 and $20,772, respectively)	**879,736**	727,976	614,173
Distributions on redeemable preferred securities of subsidiary trusts	**38,344**	38,800	38,800
Total interest charges and financing costs	**918,080**	766,776	652,973
Income (loss) from continuing operations before income taxes and minority interest	**(2,306,426)**	1,137,257	842,806
Income taxes	**(627,985)**	331,371	299,030
Minority interest	**(17,071)**	68,199	29,994
Income (loss) from continuing operations	**(1,661,370)**	737,687	513,782
Income (loss) from discontinued operations – net of tax (see Note 3)	**(556,621)**	46,992	32,006
Income (loss) before extraordinary items	**(2,217,991)**	784,679	545,788
Extraordinary items – net of income taxes of $0, $4,807 and ($8,549), respectively	**–**	10,287	(18,960)
Net income (loss)	**(2,217,991)**	794,966	526,828
Dividend requirements on preferred stock	**4,241**	4,241	4,241
Earnings available for common shareholders	**$(2,222,232)**	$ 790,725	$ 522,587
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS)			
Basic	**382,051**	342,952	337,832
Diluted	**382,051**	343,742	338,111
EARNINGS (LOSS) PER SHARE – BASIC			
Income (loss) from continuing operations	**$ (4.36)**	$ 2.14	$ 1.51
Discontinued operations (see Note 3)	**(1.46)**	0.14	0.09
Extraordinary items (see Note 15)	**–**	0.03	(0.06)
Earnings (loss) per share	**$ (5.82)**	$ 2.31	$ 1.54
EARNINGS (LOSS) PER SHARE – DILUTED			
Income (loss) from continuing operations	**$ (4.36)**	$ 2.13	$ 1.51
Discontinued operations (see Note 3)	**(1.46)**	0.14	0.09
Extraordinary items (see Note 15)	**–**	0.03	(0.06)
Earnings (loss) per share	**$ (5.82)**	$ 2.30	$ 1.54

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*2002*	*2001*	*2000*
		Year ended Dec. 31	
OPERATING ACTIVITIES			
Net income (loss)	**$(2,217,991)**	$ 794,966	$ 526,828
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	**1,028,494**	945,555	828,780
Nuclear fuel amortization	**48,675**	41,928	44,591
Deferred income taxes	**(781,531)**	11,190	62,716
Amortization of investment tax credits	**(13,272)**	(12,867)	(15,295)
Allowance for equity funds used during construction	**(7,810)**	(6,829)	3,848
Undistributed equity in earnings of unconsolidated affiliates	**(16,478)**	(124,277)	(87,019)
Gain on sale of property	**(6,785)**	–	–
Write-downs and losses from investments	**207,290**	–	–
Gain on sale of discontinued operations	**(2,814)**	–	–
Noncash special charges – asset write-downs	**3,160,374**	–	41,991
Conservation incentive accrual adjustments	**(9,152)**	(49,271)	19,248
Unrealized gain on derivative financial instruments	**(8,407)**	(9,804)	–
Extraordinary items – net of tax (see Note 15)	**–**	(10,287)	18,960
Change in accounts receivable	**126,073**	218,353	(443,347)
Change in inventories	**8,620**	(178,530)	21,933
Change in other current assets	**67,596**	340,478	(484,288)
Change in accounts payable	**80,338**	(325,946)	713,069
Change in other current liabilities	**156,471**	142,617	183,679
Change in other noncurrent assets	**(203,997)**	(329,442)	(130,764)
Change in other noncurrent liabilities	**99,417**	136,178	102,795
Net cash provided by operating activities	**1,715,111**	1,584,012	1,407,725
INVESTING ACTIVITIES			
Nonregulated capital expenditures and asset acquisitions	**(1,502,601)**	(4,259,791)	(2,196,168)
Utility capital/construction expenditures	**(906,341)**	(1,105,989)	(984,935)
Proceeds from sale of discontinued operations	**160,791**	–	–
Allowance for equity funds used during construction	**7,810**	6,829	(3,848)
Investments in external decommissioning fund	**(57,830)**	(54,996)	(48,967)
Equity investments, loans, deposits and sales of nonregulated projects	**(118,844)**	154,845	(93,366)
Restricted cash	**(220,800)**	–	–
Collection of loans made to nonregulated projects	**22,498**	6,374	17,039
Other investments – net	**(102,457)**	84,769	(36,749)
Net cash used in investing activities	**(2,717,774)**	(5,167,959)	(3,346,994)
FINANCING ACTIVITIES			
Short-term borrowings – net	**(663,365)**	708,335	42,386
Proceeds from issuance of long-term debt	**2,521,375**	3,777,075	3,565,227
Repayment of long-term debt, including reacquisition premiums	**(362,760)**	(860,623)	(1,667,335)
Proceeds from issuance of common stock	**581,212**	133,091	116,678
Proceeds from NRG stock offering	**–**	474,348	453,705
Dividends paid	**(496,375)**	(518,894)	(494,992)
Net cash provided by financing activities	**1,580,087**	3,713,332	2,015,669
Effect of exchange rate changes on cash	**6,448**	(4,566)	360
Net increase in cash and cash equivalents – discontinued operations	**56,096**	(21,570)	(57,638)
Net increase in cash and cash equivalents – continuing operations	**639,968**	103,249	19,122
Cash and cash equivalents at beginning of year	**261,305**	158,056	138,934
Cash and cash equivalents at end of year	**$ 901,273**	$ 261,305	$ 158,056
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	**$ 640,628**	$ 708,560	$ 610,584
Cash paid for income taxes (net of refunds received)	**$ 24,935**	$ 327,018	$ 216,087

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 2002	2001
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 901,273**	$ 261,305
Restricted cash	**305,581**	142,676
Accounts receivable – net of allowance for bad debts: $92,745 and $37,487, respectively	**961,060**	1,048,073
Accrued unbilled revenues	**390,984**	495,994
Materials and supplies inventories – at average cost	**321,863**	308,593
Fuel inventory – at average cost	**207,200**	250,043
Natural gas inventories – replacement cost in excess of LIFO: $20,502 and $11,331, respectively	**147,306**	126,563
Recoverable purchased natural gas and electric energy costs	**63,975**	52,583
Derivative instruments valuation – at market	**62,206**	20,794
Prepayments and other	**267,185**	307,169
Current assets held for sale	**108,535**	316,621
Total current assets	**3,737,168**	3,330,414
Property, plant and equipment, at cost:		
Electric utility plant	**16,516,790**	16,099,655
Nonregulated property and other	**8,411,088**	6,924,894
Natural gas utility plant	**2,603,545**	2,493,028
Construction work in progress: utility amounts of $856,008 and $669,895, respectively	**1,513,807**	3,663,371
Total property, plant and equipment	**29,045,230**	29,180,948
Less accumulated depreciation	**(10,303,575)**	(9,495,835)
Nuclear fuel – net of accumulated amortization: $1,058,531 and $1,009,855, respectively	**74,139**	96,315
Net property, plant and equipment	**18,815,794**	19,781,428
Other assets:		
Investments in unconsolidated affiliates	**1,001,380**	1,196,702
Notes receivable, including amounts from affiliates of $206,308 and $202,411, respectively	**987,714**	779,186
Nuclear decommissioning fund and other investments	**732,166**	695,070
Regulatory assets	**576,403**	502,442
Derivative instruments valuation – at market	**93,225**	96,095
Prepaid pension asset	**466,229**	378,825
Goodwill, net	**35,538**	36,916
Intangible assets, net	**68,210**	66,700
Other	**364,243**	360,158
Noncurrent assets held for sale	**379,772**	1,530,178
Total other assets	**4,704,880**	5,642,272
Total assets	**$27,257,842**	$28,754,114
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	**$ 7,756,261**	$ 392,938
Short-term debt	**1,541,963**	2,224,812
Accounts payable	**1,399,195**	1,263,690
Taxes accrued	**267,214**	246,098
Dividends payable	**75,814**	130,845
Derivative instruments valuation – at market	**38,767**	83,122
Other	**749,521**	698,142
Current liabilities held for sale	**520,101**	429,433
Total current liabilities	**12,348,836**	5,469,080
Deferred credits and other liabilities:		
Deferred income taxes	**1,283,667**	2,134,977
Deferred investment tax credits	**169,696**	184,148
Regulatory liabilities	**518,427**	483,942
Derivative instruments valuation – at market	**102,779**	42,444
Benefit obligations and other	**722,264**	692,090
Minimum pension liability	**106,897**	–
Noncurrent liabilities held for sale	**155,962**	783,297
Total deferred credits and other liabilities	**3,059,692**	4,320,898
Minority interest in subsidiaries	**34,762**	614,750
Commitments and contingencies (see Note 18)		
Capitalization (see Statements of Capitalization):		
Long-term debt	**6,550,248**	11,555,589
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 9)	**494,000**	494,000
Preferred stockholders' equity	**105,320**	105,320
Common stockholders' equity	**4,664,984**	6,194,477
Total liabilities and equity	**$27,257,842**	$28,754,114

See Notes to Consolidated Financial Statements

	Common Stock Issued					*Accumulated*	
(Thousands)	*Shares*	*Par Value*	*Capital in Excess of Par Value*	*Retained Earnings (Deficit)*	*Shares Held by ESOP*	*Other Comprehensive Income (Loss)*	*Total Stockholders' Equity*
Balance at Dec. 31, 1999	335,277	$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)
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 proceeds	5,557	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 *(a)*					6,989		6,989
Balance at Dec. 31, 2000	340,834	$852,085	$2,607,025	$2,284,220	$(24,617)	$(156,929)	$5,561,784
Net income				794,966			794,966
Currency translation adjustments						(56,693)	(56,693)
Cumulative effect of accounting change – net unrealized transition loss upon adoption of SFAS No. 133 (see Note 17)						(28,780)	(28,780)
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 17)						43,574	43,574
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						19,449	19,449
Unrealized loss – marketable securities						(75)	(75)
Comprehensive income for 2001							772,441
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(516,515)			(516,515)
Issuances of common stock – net proceeds	4,967	12,418	120,673				133,091
Other				(27)			(27)
Gain recognized from NRG stock offering			241,891				241,891
Repayment of ESOP loan *(a)*					6,053		6,053
Balance at Dec. 31, 2001	345,801	$864,503	$2,969,589	$2,558,403	$(18,564)	$(179,454)	$6,194,477
Net loss				(2,217,991)			(2,217,991)
Currency translation adjustments						30,008	30,008
Minimum pension liability						(107,782)	(107,782)
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 17)						(68,266)	(68,266)
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						28,791	28,791
Unrealized loss – marketable securities						(457)	(457)
Comprehensive income (loss) for 2002							(2,335,697)
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(437,113)			(437,113)
Issuances of common stock – net proceeds	27,148	67,870	513,342				581,212
Acquisition of NRG minority common shares	25,765	64,412	555,220			28,150	647,782
Repayment of ESOP loan *(a)*					18,564		18,564
Balance at Dec. 31, 2002	**398,714**	**$996,785**	**$4,038,151**	**$ (100,942)**	**$ –**	**$(269,010)**	**$4,664,984**

(a) Did not affect cash flows.

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 *2002*	*2001*
LONG-TERM DEBT		
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2003–2006, 3.75%–4.1%	$ **9,145** *(a)*	$ 11,225 *(a)*
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
Aug. 28, 2012, 8%	**450,000**	–
March 1, 2011, variable rate, 6.265% at Dec. 31, 2002, and 1.8% at Dec. 31, 2001	**13,700** *(b)*	13,700 *(b)*
March 1, 2019, 8.50% at Dec. 31, 2002, and a variable rate of 2.04% at Dec. 31, 2001	**27,900** *(b)*	27,900 *(b)*
Sept. 1, 2019, 8.5% at Dec. 31, 2002, and a variable rate of 1.76% and 2.04% at Dec. 31, 2001	**100,000** *(b)*	100,000 *(b)*
July 1, 2025, 7.125%	**250,000**	250,000
March 1, 2028, 6.5%	**150,000**	150,000
April 1, 2030, 8.50% at Dec. 31, 2002, and 1.85% at Dec. 31, 2001	**69,000** *(b)*	69,000 *(b)*
Dec. 1, 2003–2008, 4.25%–5%	**14,090** *(a)*	16,090 *(a)*
Guaranty Agreements, Series due Feb. 1, 2003–May 1, 2003, 5.375%–7.4%	**28,450** *(b)*	29,200 *(b)*
Senior Notes, due Aug. 1, 2009, 6.875%	**250,000**	250,000
Retail Notes, due July 1, 2042, 8%	**185,000**	–
Employee Stock Ownership Plan Bank Loans, variable rate	**–**	18,564
Other	**427**	390
Unamortized discount-net	**(8,931)**	(5,015)
Total	**1,788,781**	1,181,054
Less redeemable bonds classified as current (see Note 6)	**13,700**	141,600
Less current maturities	**212,762**	11,134
Total NSP-Minnesota long-term debt	**$1,562,319**	$1,028,320
PSCo Debt		
First Mortgage Bonds, Series due:		
April 15, 2003, 6%	$ **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** *(b)*	18,000 *(b)*
June 1, 2012, 5.5%	**50,000** *(b)*	50,000 *(b)*
Oct. 1, 2012, 7.875%	**600,000**	–
April 1, 2014, 5.875%	**61,500** *(b)*	61,500 *(b)*
Jan. 1, 2019, 5.1%	**48,750** *(b)*	48,750 *(b)*
March 1, 2022, 8.75%	**146,340**	147,840
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 Nov. 25, 2003–March 5, 2007, 6.45%–7.11%	**175,000**	190,000
Unamortized discount	**(4,612)**	(5,282)
Capital lease obligations, 11.2% due in installments through May 31, 2025	**49,747**	51,921
Total	**2,064,225**	1,482,229
Less current maturities	**282,097**	17,174
Total PSCo long-term debt	**$1,782,128**	$1,465,055
SPS Debt		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ **100,000**	$ 100,000
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	**500,000**	500,000
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	**44,500**	44,500
July 1, 2016, 1.6% at Dec. 31, 2002, and 1.7% at Dec. 31, 2001	**25,000**	25,000
Sept. 1, 2016, 5.75% series	**57,300**	57,300
Unamortized discount	**(1,138)**	(1,425)
Total SPS long-term debt	$ **725,662**	$ 725,375

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 2002	2001
LONG-TERM DEBT – CONTINUED		
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** (a)	18,600 (a)
Fort McCoy System Acquisition, due Oct. 31, 2030, 7%	**930**	963
Senior Notes, due Oct. 1, 2008, 7.64%	**80,000**	80,000
Unamortized discount	**(1,388)**	(1,475)
Total	**313,142**	313,088
Less current maturities	**40,034**	34
Total NSP-Wisconsin long-term debt	**$ 273,108**	$ 313,054
NRG Debt		
Remarketable or Redeemable Securities, due March 15, 2005, 7.97%	**$ 257,552**	$ 232,960
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**	350,000
July 15, 2006, 6.75%	**340,000**	340,000
April 1, 2011, 7.75%	**350,000**	350,000
April 1, 2031, 8.625%	**500,000**	500,000
May 16, 2006, 6.5%	**285,728**	284,440
NRG Finance Co. I LLC, due May 9, 2006, various rates	**1,081,000**	697,500
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	**126,500**	180,000
June 15, 2015, 8.842%	**130,000**	130,000
Dec. 15, 2024, 9.292%	**300,000**	300,000
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	**450,750**	463,500
Sept. 15, 2024, 9.479%	**300,000**	300,000
MidAtlantic – various, due Oct. 1, 2005, 4.625%	**409,201**	420,892
Flinders Power Finance Pty, due September 2012, various rates of 6.14%–6.49% at Dec. 31, 2002, and 8.56% at Dec. 31, 2001	**99,175**	74,886
Brazos Valley, due June 30, 2008, 6.75%	**194,362**	159,750
Camas Power Boiler, due June 30, 2007, and Aug. 1, 2007, 3.65% and 3.38%	**17,861**	20,909
Sterling Luxembourg #3 Loan, due June 30, 2019, variable rate of 7.86% at Dec. 31, 2001	**360,122**	329,842
Crockett Corp. LLP debt, due Dec. 31, 2014, 8.13%	**–**	234,497
Csepel Aramtermelo, due Oct. 2, 2017, 3.79% and 4.846%	**–**	169,712
Hsin Yu Energy Development, due November 2006–April 2012, 4%–6.475%	**85,607**	89,964
LSP Batesville, due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	**314,300**	321,875
LSP Kendall Energy, due Sept. 1, 2005, 2.65%	**495,754**	499,500
McClain, due Dec. 31, 2005, 6.75%	**157,288**	159,885
NEO, due 2005–2008, 9.35%	**7,658**	23,956
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	**133,099**	62,408
NRG Peaking Finance LLC, due 2019, 6.67%	**319,362**	–
NRG Pike Energy LLC, due 2010, 4.92%	**155,477**	–
PERC, due 2017–2018, 5.2%	**28,695**	33,220
Audrain Capital Lease Obligation, due Dec. 31, 2023, 10%	**239,930**	239,930
Saale Energie GmbH Schkopau Capital Lease, due May 2021, various rates	**333,926**	311,867
Various debt, due 2003–2007, 0.0%–20.8%	**92,573**	147,493
Other	**676**	–
Total	**8,831,596**	8,343,986
Less current maturities – continuing operations	**7,193,237**	210,885
Less discontinued operations	**445,729**	851,196
Total NRG long-term debt	**$1,192,630**	$7,281,905

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 *2002*	*2001*
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, 1.7% and 1.8% at Dec. 31, 2002 and 2001	**17,000**	17,000
Viking Gas Transmission Co. Senior Notes-Series due:		
Oct. 31, 2008–Sept. 30, 2014, 6.65%–8.04%	**40,421**	45,181
Various Eloigne Co. Affordable Housing Project Notes, due 2003–2027, 0.3%–9.91%	**41,353**	47,856
Other	**97,895**	35,608
Total	**208,669**	157,645
Less current maturities	**14,431**	12,110
Total other subsidiaries' long-term debt	**$ 194,238**	$ 145,535
Xcel Energy Inc. Debt		
Unsecured senior notes, due Dec. 1, 2010, 7%	**$ 600,000**	$ 600,000
Convertible notes, due Nov. 21, 2007, 7.5%	**230,000**	–
Unamortized discount	**(9,837)**	(3,655)
Total Xcel Energy Inc. debt	**$ 820,163**	$ 596,345
Total long-term debt	**$6,550,248**	$11,555,589
MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS holding as their sole asset the junior subordinated deferrable debentures of:		
NSP-Minnesota, due 2037, 7.875%	**$ 200,000**	$ 200,000
PSCo, due 2038, 7.6%	**194,000**	194,000
SPS, due 2036, 7.85%	**100,000**	100,000
Total mandatorily redeemable preferred securities of subsidiary trusts	**$ 494,000**	$ 494,000
CUMULATIVE PREFERRED STOCK – authorized 7,000,000 shares of $100 par value; outstanding shares: 2002, 1,049,800; 2001, 1,049,800		
$3.60 series, 275,000 shares	**$ 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, 99,800 shares	**9,980**	9,980
$4.56 series, 150,000 shares	**15,000**	15,000
Total	**104,980**	104,980
Capital in excess of par value on preferred stock	**340**	340
Total preferred stockholders' equity	**$ 105,320**	$ 105,320
COMMON STOCKHOLDERS' EQUITY		
Common stock – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2002, 398,714,039; 2001, 345,801,028	**$ 996,785**	$ 864,503
Capital in excess of par value on common stock	**4,038,151**	2,969,589
Retained earnings (deficit)	**(100,942)**	2,558,403
Leveraged common stock held by ESOP – shares at cost: 2002, 0; 2001, 783,162	**–**	(18,564)
Accumulated other comprehensive income (loss)	**(269,010)**	(179,454)
Total common stockholders' equity	**$4,664,984**	$ 6,194,477

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Merger and Basis of Presentation On Aug. 18, 2000, Northern States Power Co. (NSP) and New Century Energies, Inc. (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. References herein to Xcel Energy relates to Xcel Energy, Inc. and its consolidated subsidiaries.

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. During the period covered by this report, Xcel Energy's regulated businesses also included Viking, which was sold in January 2003, and WGI.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., an independent power producer. Xcel Energy owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering, and 82 percent until a secondary offering was completed in March 2001. At Dec. 31, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. During the second quarter of 2002, Xcel Energy acquired the 26 percent of NRG shares that it did not own through a tender offer and merger. See Note 4 to the Consolidated Financial Statements for further discussion of the acquisition of minority NRG common shares.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (an international independent power producer).

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 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. Under this method, we record our proportionate share of pretax income as equity earnings from investments in affiliates. 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 Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

Xcel Energy's utility subsidiaries have various rate 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. In addition Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees.

PSCo's electric rates in Colorado are adjusted under the ICA mechanism, which takes into account changes in energy costs and certain trading revenues and expenses that are shared with the customer. For fuel and purchased energy expense incurred beginning Jan. 1, 2003, the recovery mechanism shall be determined by the CPUC in the PSCo 2002 general rate case. In the interim, 2003 fuel and purchased energy expense is recovered through an interim adjustment clause.

NSP-Minnesota's rates include a cost-of-fuel and cost-of-gas recovery mechanism allowing dollar-for-dollar recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively.

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 performance-based regulatory plan, which results in an annual earnings test. NSP-Minnesota's and PSCo's rates include monthly adjustments for the recovery of conservation and energy management program costs, which are reviewed annually.

SPS' rates in Texas have fixed fuel factor and periodic fuel filing, reconciling and reporting requirements, which provide cost recovery. In New Mexico, SPS also has a monthly fuel and purchased power cost recovery factor.

Trading Operations In June 2002, the EITF of the FASB reached a partial consensus on Issue No. 02-03 – "Recognition and Reporting of Gains and Losses on Energy Trading Contracts" under EITF Issue No. 98-10 - "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-03). The EITF concluded that all gains and losses related to energy trading activities within the scope of EITF No. 98-10, whether or not settled physically, must be shown net in the statement of operations, effective for periods ending after July 15, 2002. Xcel Energy has reclassified revenue from trading activities for all comparable prior periods reported. Such energy trading activities recorded as a component of Electric and Gas Trading Costs, which have been reclassified to offset Electric and Gas Trading Revenues to present Electric and Gas Trading Margin on a net basis, were $3.3 billion, $3.1 billion and $2 billion for the years ended Dec. 31, 2002, 2001 and 2000, respectively. This reclassification had no impact on operating income or reported net income.

On Oct. 25, 2002, the EITF rescinded EITF No. 98-10. With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133 must be restated to historical cost through a cumulative effect adjustment. Xcel Energy does not expect the effect of adopting this decision to be material.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota (electric), PSCo (electric) and e prime (natural gas). Pursuant to a joint operating agreement (JOA), approved by the FERC as part of the merger, some of the electric trading activity conducted at NSP-Minnesota and PSCo is apportioned to the other operating utilities of Xcel Energy. Trading revenue and costs do not include the revenue and production costs associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Trading results are recorded using the mark-to-market accounting. In addition, trading results include the impacts of the ICA rate-sharing mechanism. Trading revenue and costs associated with NRG's operations are included in nonregulated margins. For more information, see Notes 16 and 17 to the Consolidated Financial Statements.

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 using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.4 percent, 3.1 percent and 3.3 percent for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

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 obtained for another future generating station in Colorado. 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) and Capitalized Interest 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 nonoperating income, 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 for all Xcel Energy entities, as AFDC for utility companies, was approximately $83 million in 2002, $56 million in 2001 and $23 million in 2000.

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 19 to the Consolidated Financial Statements.

PSCo also previously operated a nuclear generating plant, which has been decommissioned and repowered using natural gas. PSCo's costs associated with decommissioning were deferred and are being amortized consistent with regulatory recovery.

Nuclear Fuel Expense Nuclear fuel expense, which is recorded as our nuclear generating plants use fuel, includes the cost of fuel used in the current period, as well as future disposal costs of spent nuclear fuel. In addition, nuclear fuel expense includes fees assessed by the U.S. Department of Energy (DOE) for NSP-Minnesota's portion of the cost of decommissioning 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 flow.

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 domestic subsidiaries, other than NRG and its domestic subsidiaries, file consolidated federal income tax returns. NRG and its domestic subsidiaries were included in Xcel Energy's consolidated federal income tax returns prior to NRG's March 2001 public equity offering, but filed consolidated federal income tax returns, with NRG as the common parent, separate and apart from Xcel Energy for the periods of March 13, 2001, through Dec. 31, 2001, and Jan. 1, 2002, through June 3, 2002. Since becoming wholly owned indirect subsidiaries of Xcel Energy on June 3, 2002, NRG and its domestic subsidiaries have not been reconsolidated with Xcel Energy for federal income tax purposes, and each of NRG and its domestic subsidiaries will file separate federal income tax returns as a result of their inclusion in the Xcel Energy consolidated federal income tax return within the last five years. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries will be included in some, but not all, of these combined returns in 2002. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. In accordance with PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company. 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. Xcel Energy uses 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 20 to the Consolidated Financial Statements. We discuss our income tax policy for international operations in Note 11 to the Consolidated 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 in common stockholders' equity. 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 Nonoperating Income. Currency exchange transactions resulted in a pretax gain (loss) of $30 million in 2002, $(57) million in 2001 and $(79) million in 2000.

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, to reduce exposure to corresponding risks. The energy contracts are both financial- and commodity-based in the energy trading and energy nontrading operations. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps.

On Jan. 1, 2001, Xcel Energy adopted SFAS No. 133. For more information on the impact of SFAS No. 133, see Note 17 to the Consolidated Financial Statements.

For further discussion of Xcel Energy's risk management and derivative activities, see Notes 16 and 17 to the Consolidated 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 Items 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.

Restricted cash consists primarily of cash collateral for letters of credit issued in relation to project development activities. In addition, it includes funds held in trust accounts to satisfy the requirements of certain debt agreements and funds held within NRG's projects that are restricted in their use. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Cash and cash equivalents includes $385 million held by NRG, which is not legally restricted. However, this cash is not available for Xcel Energy's general corporate purposes.

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 pricing.

Regulatory Accounting Our regulated utility subsidiaries account for certain income and expense items using SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation." Under SFAS No. 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 ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 20 to the Consolidated Financial Statements.

Stock-Based Employee Compensation We have 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 awarded to certain employees, which is held until the restriction lapses or the stock is forfeited. For more information on stock compensation impacts, see Note 12 to the Consolidated Financial Statements.

Intangible Assets During 2002, Xcel Energy adopted SFAS No. 142 – "Goodwill and Other Intangible Assets," which requires new accounting for intangible assets and goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill is no longer being amortized, but will be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value.

Xcel Energy had goodwill of approximately $35 million at Dec. 31, 2002, which will not be amortized, consisting of $27.8 million of project-related goodwill at NRG and $7.7 million of project-related goodwill at Utility Engineering. As part of Xcel Energy's acquisition of NRG's minority shares (see Note 4), $62 million of excess purchase price was allocated to fixed assets related to projects where the fair value of the fixed assets was higher than the carrying value as of June 2002, to prepaid pension assets, and to other assets. Net goodwill decreased between 2002 and 2001 due to asset sales at NRG. During 2002, Xcel Energy performed impairment tests of its intangible assets. Tests have concluded that no write-down of these intangible assets is necessary.

Intangible assets with finite lives continue to be amortized, and the aggregate amortization expense recognized in the years ended Dec. 31, 2002, 2001 and 2000, were $4.3 million, $6.3 million and $3.9 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $3.4 million. Intangible assets consisted of the following:

(Millions of dollars)	Dec. 31, 2002 Gross Carrying Amount	Dec. 31, 2002 Accumulated Amortization	Dec. 31, 2001 Gross Carrying Amount	Dec. 31, 2001 Accumulated Amortization
Not amortized:				
Goodwill	**$42.5**	**$ 7.0**	$44.1	$ 7.2
Amortized:				
Service contracts	**$73.2**	**$17.9**	$76.2	$15.6
Trademarks	**$ 5.0**	**$ 0.5**	$ 5.0	$ 0.4
Prior service costs	**$ 6.9**	**$ –**	$ –	$ –
Other (primarily franchises)	**$ 2.0**	**$ 0.5**	$ 1.9	$ 0.4

The following table summarizes the pro forma impact of implementing SFAS No. 142 at Jan. 1, 2000, on the net income for the periods presented. The pro forma income adjustment to remove goodwill amortization is not material to earnings per share previously reported.

(Millions of dollars)	Year Ended Dec. 31, 2001	Year Ended Dec. 31, 2000
Reported income from continuing operations	$737.7	$513.8
Add back: goodwill amortization (after tax)	1.2	1.8
Adjusted income from continuing operations	$738.9	$515.6
Reported income before extraordinary items	$784.7	$545.8
Add back: goodwill amortization (after tax)	3.2	2.5
Adjusted income before extraordinary items	$787.9	$548.3
Reported net income	$795.0	$526.8
Add back: goodwill amortization (after tax)	3.2	2.5
Adjusted net income	$798.2	$529.3
Earnings per share	$ 2.31	$ 1.55

Asset Valuation On Jan. 1, 2002, Xcel Energy adopted SFAS No. 144 – "Accounting for the Impairment or Disposal of Long-Lived Assets," which supercedes previous guidance for measurement of asset impairments. Xcel Energy did not recognize any asset impairments as a result of the adoption. The method used in determining fair value was based on a number of valuation techniques, including present value of future cash flows. SFAS No. 144 is being applied to NRG's sale of assets as they are reclassified to "held for sale" and discontinued operations (see Note 3). In addition, SFAS No. 144 is being applied to test for and measure impairment of NRG's long-lived assets held for use (primarily energy projects in operation and under construction), as discussed further in Note 2 to the Consolidated Financial Statements.

Deferred Financing Costs Other assets also included deferred financing costs, net of amortization, of approximately $198 million at Dec. 31, 2002. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Diluted Earnings Per Share Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding each period. However, no common equivalent shares are included in the computation when a loss from continuing operations exists due to their antidilutive effect (that is, they would make the loss per share smaller). Therefore, common equivalent shares of approximately 5.4 million were excluded from the diluted earnings-per-share computations for the year ended Dec. 31, 2002, as shown in Note 12.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46 requiring an enterprise's consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise's consolidated financial statements do not include the consolidations of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46, the voting interest approach is not effective in identifying controlling financial interest. As a result, Xcel Energy expects that it will have to consolidate its affordable housing investments made through Eloigne, which currently are accounted for under the equity method.

As of Dec. 31, 2002, the assets of these entities were approximately $155 million and long-term liabilities were approximately $87 million. Currently, investments of $62 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2002, Consolidated Balance Sheet. FIN No. 46 requires that for entities to be consolidated, the entities' assets be initially recorded at their carrying amounts at the date the new requirement first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to Xcel Energy's balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative effect adjustment of an accounting change. Had Xcel Energy adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. Xcel Energy plans to adopt FIN No. 46 when required in the third quarter of 2003.

Reclassifications We reclassified certain items in the 2000 and 2001 statements of operations and the 2001 balance sheet to conform to the 2002 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily to conform the presentation of all consolidated Xcel Energy subsidiaries to a standard corporate presentation.

2. SPECIAL CHARGES AND ASSET IMPAIRMENTS

Special charges included in Operating Expenses for the years ended Dec. 31, 2002, 2001 and 2000, include the following:

(Millions of dollars)	***2002***	*2001*	*2000*
NRG special charges:			
Asset impairments – continuing operations	**$2,545**	$ –	$ –
Financial restructuring and NEO costs	**111**	–	–
Total NRG special charges	**2,656**	–	–
Regulated utility special charges:			
Regulatory recovery adjustment (SPS)	**5**	–	–
Restaffing (utility and service companies)	**9**	39	–
Post-employment benefits (PSCo)	**–**	23	–
Merger costs – severance and related costs	**–**	–	77
Merger costs – transaction-related	**–**	–	52
Other merger costs – transition and integration	**–**	–	70
Total regulated utility special charges	**14**	62	199
Other nonregulated special charges:			
Asset impairments	**16**	–	42
Holding company NRG restructuring charges	**5**	–	–
Total nonregulated special charges	**21**	–	42
Total special charges	**$2,691**	$62	$241

NRG Asset Impairments As discussed further in Note 4, NRG in 2002 experienced credit-rating downgrades, defaults under numerous credit agreements, increased collateral requirements and reduced liquidity. These events resulted in impairment reviews of a number of NRG assets. NRG completed an analysis of the recoverability of the asset-carrying values of its projects, factoring in the probability weighting of different courses of action available to NRG, given its financial position and liquidity constraints. This approach was applied consistently to asset groups with similar uncertainties and cash flow streams. As a result, NRG determined that many of its construction projects and its operational projects became impaired during 2002 and should be written down to fair market value. In applying those provisions, NRG management considered cash flow analyses, bids and offers related to those projects. The resulting impairments were recognized as Special Charges in 2002, as follows:

(Millions of dollars)	*Status*	*Pretax Charge*	*Fair Value Basis*
Projects in Construction or Development			
Nelson	Terminated	$ 468	Similar asset prices
Pike	Terminated – Chapter 7 involuntary bankruptcy petition filed October 2002	402	Similar asset prices
Bourbonnais	Terminated	265	Similar asset prices
Meriden	Terminated	144	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	103	Projected cash flows
Kendall, Batesville and other expansion projects	Terminated	120	Projected cash flows
Langage (UK)	Terminated	42	Estimated market price
Turbines and other costs	Equipment being marketed	702	Similar asset prices
Total		$2,246	
Operating Projects			
Audrain	Operating at a loss	$ 66	Projected cash flows
Somerset	Operating at a loss	49	Projected cash flows
Bayou Cove	Operating at a loss	127	Projected cash flows
Other	Operating at a loss	57	Projected cash flows
Total		$ 299	
Total NRG impairment charges		$2,545	

All of these impairment charges relate to assets considered held for use under SFAS No. 144. For fair values determined by similar asset prices, the fair value represents NRG's current estimate of recoverability, if the project assets were to be sold. For fair values determined by estimated market price, the fair value represents a market bid or appraisal received by NRG that NRG believes is best reflective of fair value. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operation given assumed market conditions.

Additional asset impairments may be recorded by NRG in periods subsequent to Dec. 31, 2002, given the changing business conditions and the resolution of the pending financial restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments, but it could be material.

NRG Financial Restructuring and NEO Costs In 2002, NRG expensed a pretax charge of $26 million for expected severance and related benefits related to its financial restructuring and business realignment. Through Dec. 31, 2002, severance costs have been recognized for all employees who had been terminated as of that date. See Note 4 for further discussion of NRG financial restructuring activities and developments. These costs also include a charge related to NRG's NEO landfill gas generation operations for the estimated impact of a dispute settlement with NRG's partner on the NEO project, Fortistar.

2002 Regulatory Recovery Adjustment – SPS In late 2001, SPS filed an application requesting recovery of costs incurred to comply with transition to retail competition legislation in Texas and New Mexico. During 2002, SPS entered into a settlement agreement with intervenors regarding the recovery of restructuring costs in Texas, which was approved by the state regulatory commission in May 2002. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million.

2002 Other Nonregulated Asset Impairments In 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of Xcel International's investment. Nonregulated asset impairments include a write-down of approximately $13 million for this Argentina facility.

2002 Holding Company NRG Restructuring Charges In 2002, the Xcel Energy holding company incurred approximately $5 million for charges related to NRG's financial restructuring.

2002 and 2001 – Utility Restaffing During 2001, Xcel Energy expensed pretax special charges of $39 million for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. In 2002, the identification of affected employees was completed and additional pretax special charges of $9 million were expensed for the final costs of staff consolidations. Approximately $6 million of these restaffing costs were allocated to Xcel Energy's Utility Subsidiaries. All 564 of accrued staff terminations have occurred. See the summary of costs below.

2001 – Post-employment Benefits PSCo adopted accrual accounting for post-employment benefits under SFAS No. 112 – "Employers Accounting for Post-employment Benefits" in 1994. The costs of these benefits had been recorded on a pay-as-you-go basis and, accordingly, PSCo recorded a regulatory asset in anticipation of obtaining future rate recovery of these transition 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 post-employment benefit costs on an accrual basis, but denied PSCo's request to amortize the transition costs' regulatory asset. Following various appeals, which proved unsuccessful, PSCo wrote off $23 million pretax of regulatory assets related to deferred post-employment benefit costs as of June 30, 2001.

2000 – Merger Costs At the time of the NCE and NSP-Minnesota merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million.

The pretax charges included $199 million associated with the costs of merging regulated operations. Of these pretax charges, $52 million related to one-time, transaction-related costs incurred in connection with the merger of NSP and NCE, and $147 million pertained to incremental costs of transition and integration activities associated with merging NSP and NCE to begin operations as Xcel Energy. The transition costs include approximately $77 million for severance and related expenses associated with staff reductions. All 721 of accrued staff terminations have occurred. The staff reductions were nonbargaining 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. An allocation of the regulated portion of merger costs was made to utility operating companies using a basis consistent with prior regulatory filings, in proportion to expected merger savings by company and consistent with service company cost allocation methodologies utilized under the PUHCA requirements.

The pretax charges also included $42 million of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy's nonregulated businesses.

Accrued Special Charges – The following table summarizes activity related to accrued special charges in 2002 and 2001:

(Millions of dollars)	*Utility Severance **	*NRG Severance ***	*Merger Transition Costs **
Balance at Dec. 31, 1999	$ –	$ –	$ –
2000 accruals recorded – merger costs	77	–	70
Adjustments/revisions to prior accruals	–	–	–
Cash payments made in 2000	(29)	–	(63)
Balance at Dec. 31, 2000	48	–	7
2001 accruals recorded – restaffing	39	–	–
Adjustments/revisions to prior accruals	-	–	–
Cash payments made in 2001	(50)	–	(7)
Balance at Dec. 31, 2001	37	–	–
2002 accruals recorded – various	–	23	–
Adjustments/revisions to prior accruals	9	–	–
Cash payments made in 2002	(33)	(5)	–
Balance at Dec. 31, 2002	**$13**	**$18**	**$ –**

* *Reported on the balance sheet in Other Current Liabilities.*

** *$15.5 million reported on the balance sheet in Other Current Liabilities and $2.5 million reported in Benefit Obligations and Other.*

3. DISCONTINUED OPERATIONS AND LOSSES ON EQUITY INVESTMENTS

Pursuant to the requirements of SFAS No. 144, NRG has classified and is accounting for certain of its assets as held for sale at Dec. 31, 2002. SFAS No. 144 requires that assets held for sale be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, NRG's management considered cash flow analyses, bids and offers related to those assets and businesses. As a result, NRG recorded estimated after-tax losses on assets held for sale of $5.8 million for the year ended Dec. 31, 2002. This amount is included in Income (loss) from discontinued operations in the accompanying Statement of Operations. In accordance with the provisions of SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

DISCONTINUED OPERATIONS

During 2002, NRG agreed to sell certain assets and has entered into purchase and sale agreements or has committed to a plan to sell. As of Dec. 31, 2002, five international projects (Bulo Bulo, Csepel, Entrade, Killingholme and Hsin Yu) and one domestic project (Crockett Cogeneration) had been classified as held for sale. The assets and liabilities of these six projects have been reclassified to the held-for-sale category on the balance sheet and meet the requirements of SFAS No. 144 for discontinued operations reporting. As of Dec. 31, 2002, only Hsin Yu and Killingholme's assets and liabilities remain in the held-for-sale categories of the balance sheet as the other entities have been sold. Accordingly, operating results and estimated losses on disposal of these six projects have been reclassified to discontinued operations for current and prior periods.

Projects included in discontinued operations are as follows:

(Millions of dollars) *Project*	*Location*	*Pretax Disposal Gain (Loss)*	*Status*
Crockett Cogeneration	United States	$(11.5)	Sale final 2002
Bulo Bulo	Bolivia	(10.6)	Sale final 2002
Csepel	Hungary	21.2	Sale final 2002
Entrade	Czech Republic	2.8	Sale final 2002
Killingholme*	United Kingdom	–	Sale final 2003
Hsin Yu	Taiwan	–	Held for sale
Other	Various	0.9	Sales final 2002
Total		$ 2.8	

* *The foreclosure of Killingholme in January 2003 for a gain of $182.3 million*

(Thousands of dollars)	***Year Ended Dec. 31 2002***	*Year Ended Dec. 31 2001*	*Year Ended Dec. 31 2000*
Operating revenue	**$ 729,408**	$597,181	$347,848
Operating and other expenses	**1,300,131**	544,837	310,007
Pretax (loss)/income from operations of discontinued components	**(570,723)**	52,344	37,841
Income tax (benefit)/expense	**(8,296)**	5,352	5,835
(Loss)/income from operations of discontinued components	**(562,427)**	46,992	32,006
Estimated pretax gain on disposal of discontinued components	**2,814**	–	–
Income tax (benefit)/expense	**(2,992)**	–	–
Gain on disposal of discontinued components	**5,806**	–	–
Net (loss)/income on discontinued operations	**$(556,621)**	$ 46,992	$ 32,006

Special charges from discontinued operations included in Operating and Other Expenses previously include the following:

(Thousands of dollars)	***2002***	*2001*	*2000*
Asset impairments			
Killingholme	**$ 477,868**	$ –	$ –
Hsin Yu	**121,864**	–	–
	599,732	–	–
Severance and other charges	**7,389**	–	–
Total special charges	**$ 607,121**	$ –	$ –

These impairment charges relate to assets considered held for sale under SFAS No. 144, as of Dec. 31, 2002. In January 2003, Killingholme was transferred to the project lenders. Hsin Yu has historically operated at a loss and its funding has been discontinued as of Dec. 31, 2002. The fair values represent discounted cash flows over the remaining life of each project and reflect project-specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operation given assumed market conditions.

The major classes of assets and liabilities held for sale are as follows as of Dec. 31:

(Thousands of dollars)	*2002*	*2001*
Cash	$ 23,911	$ 99,171
Receivables, net	28,220	129,220
Derivative instruments valuation – at market	29,795	38,996
Other current assets	26,609	49,234
Current assets held for sale	108,535	316,621
Property, plant and equipment, net	274,544	1,383,690
Derivative instruments valuation – at market	87,803	83,588
Other noncurrent assets	17,425	62,900
Noncurrent assets held for sale	379,772	1,530,178
Current portion of long-term debt	445,656	289,269
Accounts payable – trade	55,707	97,654
Other current liabilities	18,738	42,510
Current liabilities held for sale	520,101	429,433
Long-term debt	73	561,927
Deferred income tax	129,640	154,573
Derivative instruments valuation – at market	12,302	15,131
Other noncurrent liabilities	13,947	51,666
Noncurrent liabilities held for sale	$155,962	$783,297

Included in other noncurrent assets held for sale is approximately $27 million, net of $3.6 million of amortization, of goodwill and $11 million, net of $1.9 million of amortization, of intangible assets as of Dec. 31, 2002. There are no amounts of goodwill or intangible assets included in noncurrent assets held for sale.

LOSSES RELATED TO NRG EQUITY INVESTMENTS

As of Dec. 31, 2002, several projects of NRG incurred losses related to disposal transactions or asset impairments. In the accompanying financial statements, the operating results of these projects are classified in equity earnings from investments in affiliates, and write-downs of the carrying amount of the investments and losses on disposal have been classified and reported as a component of write-downs and disposal losses from investments. During 2002, NRG recorded write-downs and losses on disposal of $196.2 million of equity investments as follows:

(Millions of dollars) *Project*	*Location*	*Impairment Loss*	*Disposal Gain (Loss)*	*Status*
Collinsville	Australia	$ –	$ (3.6)	Sale final 2002
EDL	Australia	$ –	$(14.2)	Sale final 2002
ECKG	Czech Republic	$ –	$ (2.1)	Sale final 2003
SRW Cogeneration	United States	$ –	$(48.4)	Sale final 2002
Mt. Poso	United States	$ –	$ (1.0)	Sale final 2002
Kingston	Canada	$ –	$ 9.9	Sale final 2002
Kondapalli	India	$ (12.7)	$ –	Sale pending
Loy Yang	Australia	$(111.4)	$ –	Operating
NEO MESI	United States	$ –	$ 2.0	Sale final 2002
Other		$ (14.7)	$ –	
Total		$(138.8)	$(57.4)	

During fourth quarter 2002, NRG and the other owners of the Loy Yang project engaged in a joint marketing of the project for possible sale. Based on a new market valuation and negotiations with a potential purchaser, NRG recorded a write-down of $58 million in the fourth quarter of 2002, in addition to the $54 million previously recorded in 2002. At Dec. 31, 2002, the carrying value of the investment in Loy Yang is approximately $72.9 million. Accumulated other comprehensive loss at Dec. 31, 2002, includes a reduction for foreign currency translation losses of approximately $77 million related to Loy Yang. The foreign currency translation losses will continue to be included as a component of accumulated other comprehensive loss until NRG commits to a plan to dispose of its investment.

OTHER EQUITY INVESTMENT LOSSES

Yorkshire Power Group Sale In August 2002, Xcel Energy announced it had sold its 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. Xcel Energy and American Electric Power Co. each held a 50-percent interest in Yorkshire, a UK retail electricity and gas supplier and electricity distributor, before selling 94.75 percent of Yorkshire to Innogy Holdings plc in April 2001. The sale of the 5.25-percent interest resulted in an after-tax loss of $8.3 million, or 2 cents per share, in the third quarter of 2002. The loss is included in write-downs and disposal losses from investments on the Consolidated Statements of Operations.

4. NRG ACQUISITION AND RESTRUCTURING PLAN

During 2002, Xcel Energy acquired all of the 26 percent of NRG shares not then owned by Xcel Energy through a tender offer and merger involving a tax-free exchange of 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. The transaction was completed on June 3, 2002.

The exchange of NRG common shares for Xcel Energy common shares was accounted for as a purchase. The 25,764,852 shares of Xcel Energy stock issued were valued at $25.14 per share, based on the average market price of Xcel Energy shares for three days before and after April 4, 2002, when the revised terms of the exchange were announced and recommended by the independent members of the NRG board. Including other costs of acquisition, this resulted in a total purchase price to acquire NRG's shares of approximately $656 million.

The process to allocate the purchase price to underlying interests in NRG assets and to determine fair values for the interests in assets acquired resulted in approximately $62 million of amounts being allocated to fixed assets related to projects where the fair values were in excess of carrying values, to prepaid pension assets and to other assets. The preliminary purchase price allocation is subject to change as the final purchase price allocation and asset valuation process is completed.

In December 2001, Moody's Investor Service (Moody's) placed NRG's long-term senior unsecured debt rating on review for possible downgrade. In February 2002, in response to this threat to NRG's investment grade rating, Xcel Energy announced a financial improvement plan for NRG, which included an initial step of acquiring 100 percent of NRG through a tender offer and merger involving a tax-free exchange of 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. The transaction was completed on June 3, 2002. In addition, the initial plan included financial support to NRG from Xcel Energy, marketing certain NRG generating assets for possible sale, canceling and deferring capital spending for NRG projects and combining certain of NRG's functions with Xcel Energy's systems and organization. During 2002, Xcel Energy provided NRG with $500 million of cash infusions. Throughout this period, Xcel Energy was in discussions with credit agencies and believed that its actions would be sufficient to avoid a downgrade of NRG's credit rating.

However, even with NRG's efforts to avoid a downgrade, on July 26, 2002, Standard & Poor's (S&P) downgraded NRG's senior unsecured bonds below investment grade, and, three days later, Moody's also downgraded NRG's senior unsecured debt rating below investment grade. Over the next few months, NRG senior unsecured debt, as well as the secured NRG Northeast Generating LLC bonds, the secured NRG South Central Generating LLC bonds and secured LSP Energy (Batesville) bonds were downgraded multiple times. After NRG failed to make the payment obligations due under certain unsecured bond obligations on Sept. 16, 2002, both Moody's and S&P lowered their ratings on NRG's unsecured bonds once again. Currently, unsecured bond obligations carry a rating of between CCC and D at S&P and between Ca and C at Moody's, depending on the specific debt issue.

Many of the corporate guarantees and commitments of NRG and its subsidiaries require that they be supported or replaced with letters of credit or cash collateral within 5 to 30 days of a ratings downgrade below investment grade by Moody's or S&P. As a result of the multiple downgrades, NRG estimated that it would be required to post collateral of approximately $1.1 billion.

Starting in August 2002, NRG engaged in the preparation of a comprehensive business plan and forecast. The business plan detailed the strategic merits and financial value of NRG's projects and operations. It also anticipated that NRG would function independently from Xcel Energy and thus all plans and efforts to combine certain functions of the companies were terminated. NRG utilized independent electric revenue forecasts from an outside energy markets consulting firm to develop forecasted cash flow information included in the business plan. NRG management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations would be insufficient to service recourse debt obligations. Based on this information and in consultation with Xcel Energy and its financial advisor, NRG prepared and submitted a restructuring plan in November 2002 to various lenders, bondholders and other creditor groups (collectively, NRG's creditors) of NRG and its subsidiaries. The restructuring plan was expected to serve as a basis for negotiations with NRG's creditors in a financially restructured NRG.

The restructuring plan also included a proposal by Xcel Energy that in return for a release of any and all claims against Xcel Energy, upon consummation of the restructuring, Xcel Energy would pay $300 million to NRG and surrender its equity ownership of NRG.

In mid-December 2002, the NRG bank steering committee submitted a counterproposal and in January 2003, the bondholder credit committee issued its counterproposal to the NRG restructuring plan. The counterproposal would request substantial additional payments by Xcel Energy. A new NRG restructuring proposal was presented to the creditors at the end of January 2003. A preliminary settlement has been reached with NRG's creditors. Since many of these conditions are not within Xcel Energy's control, Xcel Energy cannot state with certainty that the settlement will be effectuated. Nevertheless, Xcel Energy management is optimistic at this time that the settlement will be implemented.

On March 26, 2003, Xcel Energy's board of directors approved a tentative settlement with holders of most of NRG's long-term notes and the steering committee representing NRG's bank lenders regarding alleged claims of such creditors against Xcel Energy, including claims related to the support and capital subscription agreement between Xcel Energy and NRG dated May 29, 2002 (Support Agreement). The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement as of the date of this report were as follows:

Xcel Energy would pay up to $752 million to NRG to settle all claims of NRG and the claims of NRG against Xcel Energy, including all claims under the Support Agreement.

$350 million would be paid at or shortly following the consummation of a restructuring of NRG's debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on Jan. 1, 2004, and all or any part of such payment could be made, at Xcel Energy's election, in Xcel Energy common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that Xcel Energy had not received at such time tax refunds equal to $352 million associated with the loss on its investment in NRG. To the extent Xcel Energy had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of the Xcel Energy payments are contingent on receiving releases from NRG creditors. To the extent Xcel Energy does not receive a release from an NRG creditor, Xcel Energy's obligation to make $390 million of the payments would be reduced based on the amount of the creditor's claim against NRG. As noted below, however, the entire settlement is contingent upon Xcel Energy receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that Xcel Energy's payment obligations would be reduced by more than approximately $60 million. Any reduction would come from the Xcel Energy payment due on April 30, 2004.

Upon the consummation of NRG's debt restructuring through a bankruptcy proceeding, Xcel Energy's exposure on any guarantees or other credit supported obligations incurred by Xcel Energy for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by Xcel Energy would be returned to it. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with Xcel Energy, any intercompany claims of Xcel Energy against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of Jan. 31, 2003, will be reduced from approximately $55 million as asserted by Xcel Energy to $13 million. The $13 million agreed amount is to be paid upon the consummation of NRG's debt restructuring with $3 million in cash and an unsecured promissory note of NRG on market terms in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with Xcel Energy or any of its other affiliates for tax purposes at any time after their June 2002 re-affiliation or treated as a party to or otherwise entitled to the benefits of any tax-sharing agreement with Xcel Energy. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss Xcel Energy expects to incur in connection with the write-down of its investment in NRG.

Xcel Energy's obligations under the tentative settlement, including its obligations to make the payments described previously, are contingent upon, among other things, the following:

- definitive documentation, in form and substance satisfactory to the parties;
- between 50 percent and 100 percent of the claims represented by various NRG facilities or creditor groups (NRG Credit Facilities) having executed an agreement, in form and substance satisfactory to Xcel Energy, to support the settlement;
- various stages of the implementation of the settlement occurring by dates currently being negotiated, with the consummation of the settlement to occur by Sept. 30, 2003;
- the receipt of releases in favor of Xcel Energy by at least 85 percent of the claims represented by the NRG Credit Facilities;
- the receipt by Xcel Energy of all necessary regulatory approvals; and
- no downgrade prior to consummation of the settlement of any Xcel Energy credit rating from the level of such rating as of March 25, 2003.

Based on the foreseeable effects of a settlement agreement with the major NRG noteholders and bank lenders and the tax effect of an expected write-off of Xcel Energy's investment in NRG, Xcel Energy would recognize the expected tax benefits of the write-off as of Dec. 31, 2002. The tax benefit has been estimated at approximately $706 million. This benefit is based on the tax basis of Xcel Energy's investment in NRG.

Xcel Energy expects to claim a worthless stock deduction in 2003 on its investment. This would result in Xcel Energy having a net operating loss for the year. Under current law, this 2003 net operating loss could be carried back two years for federal purposes. Xcel Energy expects to file for a tax refund of approximately $355 million in first quarter 2004. This refund is based on a two-year carryback. However, under the Bush administration's new dividend tax proposal, the carryback could be one year, which would reduce the refund to $125 million.

As to the remaining $351 million of expected tax benefits, Xcel Energy expects to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The amount of cash freed up by the reduction in estimated tax payments would depend on Xcel Energy's taxable income.

Negotiations are ongoing. There can be no assurance that NRG creditors ultimately will accept any consensual restructuring plan, or whether, in the interim, NRG lenders and bondholders will forbear from exercising any or all of the remedies available to them, including acceleration of NRG's indebtedness, commencement of an involuntary proceeding in bankruptcy and, in the case of a certain lender, realization on the collateral for their indebtedness.

Throughout the restructuring process, NRG seeks to operate the business in a manner that NRG management believes will offer to creditors similar protection as would be offered by a bankruptcy court. NRG attempts to preserve the enterprise value of the business and to treat creditors within each creditor class without preference, unless otherwise agreed to by advisors to all potentially affected creditors. By operating NRG within this framework, NRG desires to mitigate the risk that creditors will pursue involuntary bankruptcy proceedings against NRG or its material subsidiaries.

Whether or not NRG reaches a consensual arrangement with NRG's creditors, there is a substantial likelihood that NRG will be the subject of a bankruptcy proceeding. If an agreement were reached with NRG's Creditors on a restructuring plan, it is expected that NRG would commence a Chapter 11 bankruptcy case and immediately seek approval of a prenegotiated plan of reorganization. Absent an agreement with NRG's Creditors and the continued forbearance by such creditors, NRG will be subject to substantial doubt as to its ability to continue as a going concern and will likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved and may involve claims against Xcel Energy under the equitable doctrine of substantive consolidation.

Potential NRG Bankruptcy A preliminary settlement agreement with NRG's creditors on a comprehensive financial restructuring plan that, among other things, addresses Xcel Energy's continuing role and degree of ownership in NRG and obligations to NRG in a restructured NRG has been reached. Following an agreement on the restructuring with NRG's creditors and as described previously, it is expected that NRG would commence a Chapter 11 bankruptcy proceeding and immediately seek approval of a prenegotiated plan of reorganization. Absent an agreement with NRG's creditors and the continued forbearance by such creditors, NRG will be subject to substantial doubt as to its ability to continue as a going concern and will likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities, consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. Xcel Energy believes that any effort to substantively consolidate Xcel Energy with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims or other claims under piercing the corporate veil, alter ego or related theories should an NRG bankruptcy proceeding commence, particularly in the absence of a prenegotiated plan of reorganization, and Xcel Energy cannot be certain how a bankruptcy court would resolve these issues. One of the creditors of an NRG project, as previously discussed, has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and Xcel Energy. If a bankruptcy court were to allow substantive consolidation of Xcel Energy and NRG, it would have a material adverse effect on Xcel Energy.

The accompanying Consolidated Financial Statements do not reflect any conditions or matters that would arise if NRG were in bankruptcy.

If NRG were to file for bankruptcy, and the necessary actions were taken by Xcel Energy to fully relinquish its effective control over NRG, Xcel Energy anticipates that NRG would no longer be included in Xcel Energy's consolidated financial statements, prospectively from the date such actions were taken. Such de-consolidation of NRG would encompass a change in Xcel Energy's accounting for NRG to the equity method, under which Xcel Energy would continue to record its interest in NRG's income or losses until Xcel Energy's investment in NRG (under the equity method) reached the level of obligations that Xcel Energy had either guaranteed on behalf of NRG or was otherwise committed to in the form of financial assistance to NRG. Prior to completion of a bankruptcy proceeding, a prenegotiated plan of reorganization or other settlement reached with NRG's creditors would be the determining factors in assessing whether a commitment to provide financial assistance to NRG existed at the time of de-consolidation.

At Dec. 31, 2002, Xcel Energy's pro forma investment in NRG, calculated under the equity method if applied at that date, was a negative $625 million. If the amount of guarantees or other financial assistance committed to NRG by Xcel Energy exceeded that level after de-consolidation of NRG, then NRG's losses would continue to be included in Xcel Energy's results until the amount of negative investment in NRG reaches the amount of guarantees and financial assistance committed to by Xcel Energy. As of Dec. 31, 2002, the estimated guarantee exposure that Xcel Energy had related to NRG liabilities was $96 million, as discussed in Note 16, and potential financial assistance was committed in the form of a support and capital subscription agreement pursuant to which Xcel Energy agreed, under certain circumstances, to provide an additional $300 million contribution to NRG if the financial restructuring plan discussed earlier is approved by NRG's creditors. Additional commitments for financial assistance to NRG could be created in 2003 as Xcel Energy, NRG and NRG's creditors continue to negotiate terms of a possible prenegotiated plan of reorganization to resolve NRG's financial difficulties.

In addition to the effects of NRG's losses, Xcel Energy's operating results and retained earnings in 2003 could also be affected by the tax effects of any guarantees or financial commitments to NRG, if such income tax benefits were considered likely of realization in the foreseeable future. The income tax benefits recorded in 2002 related to Xcel Energy's investment in NRG, as discussed in Note 11 to the Consolidated Financial Statements, includes only the tax benefits related to cash and stock investments already made in NRG at Dec. 31, 2002. Additional tax benefits could be recorded in 2003 at the time that such benefits are considered likely of realization, when the payment of guarantees and other financial assistance to NRG become probable.

Xcel Energy believes that the ultimate resolutions of NRG's financial difficulties and going-concern uncertainty will not affect Xcel Energy's ability to continue as a going concern. Xcel Energy is not dependent on cash flows from NRG, nor is Xcel Energy contingently liable to creditors of NRG in an amount material to Xcel Energy's liquidity. Xcel Energy believes that its cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund its non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, Xcel Energy believes it will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG's financial restructuring plan.

5. SHORT-TERM BORROWINGS

Notes Payable and Commercial Paper Information regarding notes payable and commercial paper for the years ended Dec. 31, 2002 and 2001, is:

(Millions of dollars, except interest rates)	*2002*	*2001*
Notes payable to banks	**$1,542**	$ 835
Commercial paper	**–**	1,390
Total short-term debt	**$1,542**	$2,225
Weighted average interest rate at year-end	**4.33%**	3.41%

Credit Facilities As of Dec. 31, 2002, Xcel Energy had the following credit facilities available:

	Maturity	*Term*	*Credit Line*
Xcel Energy	November 2005	5 years	$400 million
NSP-Minnesota	August 2003	364 days	$300 million
PSCo	June 2003	364 days	$530 million
SPS	February 2003	364 days	$250 million
Other subsidiaries	Various	Various	$ 55 million

The lines of credit provide short-term financing in the form of bank loans and letters of credit and, depending on credit ratings, provide support for commercial paper borrowings. At Dec. 31, 2002, there were $399 million of loans outstanding under the Xcel Energy line of credit and $88 million for PSCo. The borrowing rates under these lines of credit are based on the applicable London Interbank Offered Rate (LIBOR) plus an applicable spread, a euro dollar rate margin and the amount of money borrowed. At Dec. 31, 2002, the weighted average interest rate would have been 2.70 percent and 2.42 percent, respectively. See discussion of NRG short-term debt at Note 7.

On Jan. 22, 2003, Xcel Energy entered into an agreement with Perry Capital and King Street Capital to provide Xcel Energy with a nine-month, $100-million term loan facility. The facility carries a 9-percent per annum coupon rate and fees for early termination, prepayment and extensions within the nine-month period. Xcel Energy has no current need to draw on the facility, but sought the additional liquidity to provide financing flexibility. Xcel Energy, absent SEC approval under PUHCA, can only draw on this facility when its common equity exceeds 30 percent of total capitalization.

The SPS $250-million facility expired in February 2003 and was replaced with a $100-million unsecured, 364-day credit agreement. The NSP-Minnesota and PSCo credit facilities are secured by first mortgages and first collateral trust bonds, respectively.

6. LONG-TERM DEBT

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

The utility subsidiaries' first mortgage bond indentures provide for the ability to have sinking-fund requirements. These annual sinking-fund requirements are 1 percent of the highest principal amount of the series of first mortgage bonds at any time outstanding. Sinking-fund requirements at NSP-Wisconsin, PSCo and Cheyenne are $2.8 million and are for one series of first mortgage bonds each. Such sinking-fund requirements may be satisfied with property additions or cash. NSP-Minnesota and SPS have no sinking-fund requirements.

NSP-Minnesota's 2011 series bonds are redeemable upon seven-days notice at the option of the bondholder. Because of the terms that allow the holders to redeem these bonds on short notice, we include them in the current portion of long-term debt reported under current liabilities on the balance sheets.

See discussion of NRG long-term debt at Note 7.

Maturities and sinking fund requirements of long-term debt are:

2003	$7,759 million
2004	$ 239 million
2005	$ 313 million
2006	$ 722 million
2007	$ 420 million

7. NRG DEBT AND CAPITAL LEASES

As of Dec. 31, 2002, NRG has failed to make scheduled payments on interest and/or principal on approximately $4 billion of its recourse debt and is in default under the related debt instruments. These missed payments also have resulted in cross-defaults of numerous other nonrecourse and limited recourse debt instruments of NRG. In addition to the missed debt payments, a significant amount of NRG's debt and other obligations contain terms that require that they be supported with letters of credit or cash collateral following a ratings downgrade. As a result of the downgrades that NRG has experienced in 2002, NRG estimates that it is in default of its obligations to post collateral ranging from $1.1 billion to $1.3 billion, principally to fund equity guarantees associated with its construction revolver financing facility, to fund debt service reserves and other guarantees related to NRG projects and to fund trading operations. Absent an agreement on a comprehensive restructuring plan, NRG will remain in default under its debt and other obligations because it does not have sufficient funds to meet such requirements and obligations. As a result, the lenders will be able, if they choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG. There can be no assurance that NRG's creditors ultimately will accept any consensual restructuring plan, or that, in the interim, NRG's lenders and bondholders will continue to forbear from exercising any or all of the remedies available to them, including acceleration of NRG's indebtedness, commencement of an involuntary proceeding in bankruptcy and, in the case of certain lenders, realization on the collateral for their indebtedness. See Note 4 for discussion of 2003 developments regarding NRG's financial restructuring.

Pending the resolution of NRG's credit contingencies and the timing of possible asset sales, a portion of NRG's long-term debt obligations has been classified as current liabilities for those long-term obligations that lenders have the ability to accelerate such debt within 12 months of the balance sheet date.

LONG-TERM AND SHORT-TERM DEBT DEFAULTS

NRG and its subsidiaries had failed to timely make the following interest and/or principal payments on their indebtedness:

(Millions of dollars) Debt	*Amount Issued*	*Rate*	*Maturity*	*Interest Due*	*Principal Due*	*Date Due*
Recourse Debt (unsecured)						
NRG Energy ROARS	$ 250.0	8.700%	3/15/2005	$10.9	$ 0.0	9/16/2002
	$ 250.0	8.700%	3/15/2005	$10.9	$ 0.0	3/17/2003
NRG Energy senior notes	$ 350.0	8.250%	9/15/2010	$14.4	$ 0.0	9/16/2002
	$ 350.0	8.250%	9/15/2010	$14.4	$ 0.0	3/17/2003
NRG Energy senior notes	$ 350.0	7.750%	4/1/2011	$13.6	$ 0.0	10/1/2002
NRG Energy senior notes	$ 500.0	8.625%	4/1/2031	$21.6	$ 0.0	10/1/2002
NRG Energy senior notes	$ 240.0	8.000%	11/1/2003	$ 9.6	$ 0.0	11/1/2002
NRG Energy senior notes	$ 300.0	7.500%	6/1/2009	$11.3	$ 0.0	12/1/2002
NRG Energy senior notes	$ 250.0	7.500%	6/15/2007	$ 9.4	$ 0.0	12/15/2002
NRG Energy senior notes	$ 340.0	6.750%	7/15/2006	$11.5	$ 0.0	1/15/2003
NRG Energy senior debentures (NRZ Equity Units)	$ 287.5	6.500%	5/16/2006	$ 4.7	$ 0.0	11/16/2002
	$ 287.5	6.500%	5/16/2006	$ 4.7	$ 0.0	2/17/2003
NRG Energy senior notes	$ 125.0	7.625%	2/1/2006	$ 4.8	$ 0.0	2/1/2003
NRG Energy 364-day corporate revolving facility	$1,000.0	various	3/7/2003	$ 7.6	$ 0.0	9/30/2002
NRG Energy 364-day corporate revolving facility	$1,000.0	various	3/7/2003	$18.6	$ 0.0	12/31/2002
Nonrecourse Debt (secured)						
NRG Northeast Generating LLC	$ 320.0	8.065%	12/15/2004	$ 5.1	$53.5	12/15/2002
NRG Northeast Generating LLC	$ 130.0	8.842%	6/15/2015	$ 5.7	$ 0.0	12/15/2002
NRG Northeast Generating LLC	$ 300.0	9.292%	12/15/2024	$13.9	$ 0.0	12/15/2002
NRG South Central Generating LLC	$ 500.0	8.962%	3/15/2016	$20.2	$12.8	9/16/2002
	$ 500.0	8.962%	3/15/2016	$ 0.0	$12.8	3/17/2003
NRG South Central Generating LLC	$ 300.0	9.479%	9/15/2024	$14.2	$ 0.0	9/16/2002

These missed payments may have also resulted in cross-defaults of numerous other nonrecourse and limited recourse debt instruments of NRG.

SHORT-TERM DEBT

NRG had an unsecured, revolving line of credit of $1 billion, which terminated on March 7, 2003. At Dec. 31, 2002, NRG had a $1-billion outstanding balance under this credit facility. NRG has failed to make interest payments when due. In addition, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio requirements of the facility. On Feb. 27, 2003, NRG received a notice of default on the corporate revolver financing facility, rendering the debt immediately due and payable. The recourse revolving credit facility matured on March 7, 2003, and the $1 billion drawn remains outstanding. Accordingly, the facility is in default.

NRG's $125-million syndicated letter of credit facility contains terms, conditions and covenants that are substantially the same as those in NRG's $1-billion, 364-day revolving line of credit. As of Dec. 31, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio requirements of the facility. Accordingly, the facility is in default. NRG had $110 million and $170 million in outstanding letters of credit as of Dec. 31, 2002 and 2001, respectively.

LONG-TERM DEBT – CORPORATE DEBT

Equity Units and Debentures In 2001, NRG completed the sale of 11.5 million equity units for an initial price of $25 per unit. Each equity unit initially consists of a corporate unit comprising a $25 principal amount of NRG's senior debentures and an obligation to acquire shares of NRG common stock no later than May 18, 2004, at a price ranging from between $27.00 and $32.94. Approximately $4.1 million of the gross proceeds have been recorded as additional paid in capital to reflect the value of the obligation to purchase NRG's common stock. As a result of the merger by Xcel Energy of NRG, holders of the equity units are no longer obligated to purchase shares of NRG common stock under the purchase contracts. Instead, holders of the equity units are now obligated to purchase a number of shares of Xcel Energy common stock upon settlement of the purchase contracts equal to the adjusted "settlement rate" or the adjusted "early settlement rate" as applicable. As a result of the short-form merger, the adjusted settlement rate is 0.4630, resulting in a settlement price of approximately $55 per Xcel Energy common share, and the adjusted early settlement rate is 0.3795, resulting in a settlement price of approximately $65 per Xcel Energy common share, subject to the terms and conditions of the purchase contracts set forth in a purchase contract agreement. In October 2002, NRG announced it would not make the November 2002 quarterly interest payment on the 6.50-percent senior unsecured debentures due in 2006, which trade with the associated equity units. The 30-day grace period to make payment ended Dec. 16, 2002, and NRG did not make payment. As a result, this issue is in default. In addition, NRG did not make the Feb. 17, 2003, quarterly interest payment. In the event of an NRG bankruptcy, the obligation to purchase shares of Xcel Energy stock terminates.

Senior Unsecured Notes The NRG $125-million, $250-million, $300-million, $350-million and $240-million senior notes are unsecured and are used to support equity requirements for projects acquired and in development. The interest is paid semi-annually. The 30-day grace period to make payment related to these issues has passed. NRG did not make the required payments and is in default on these notes.

Remarketable or Redeemable Securities The $240-million NRG senior notes due Nov. 1, 2013, are remarketable or redeemable securities (ROARS). Nov. 1, 2003, is the first remarketing date for these notes. Interest is payable semi-annually on May 1 and Nov. 1 of each year through 2003, and then at intervals and interest rates as discussed in the indenture. On the remarketing date, the notes must either be mandatorily tendered to and purchased by Credit Suisse Financial Products or mandatorily redeemed by NRG at prices discussed in the indenture. The notes are unsecured debt that rank senior to all of NRG's existing and future subordinated indebtedness. On Oct. 16, 2002, NRG entered into a termination agreement with the agent that terminated the remarketing agreement. A termination payment of $31.4 million due on Oct. 17, 2002, has not been paid.

In March 2000, an NRG sponsored non-consolidated pass-through trust issued $250 million of 8.70-percent certificates due March 15, 2005. Each certificate represents a fractional undivided beneficial interest in the assets of the trust. Interest is payable on the certificates semi-annually on March 15 and Sept. 15 of each year through 2005. The sole assets of the trust consist of £160 million, approximately $250 million on the date of issuance, principal amount 7.97 percent Reset Senior Notes due March 15, 2020, issued by NRG. The Reset Senior Notes were used principally to finance NRG's acquisition of the Killingholme facility. Interest is payable semi-annually on the Reset Senior Notes on March 15 and Sept. 15 through March 15, 2005, and then at intervals and interest rates established in a remarketing process. If the Reset Senior Notes are not remarketed on March 15, 2005, they must be mandatorily redeemed by NRG on such date. On Sept. 16, 2002, NRG Pass-through Trust I failed to make a $10.9-million interest payment due on the $250 million bonds, as a consequence of NRG failing to pay interest due on £160 million of 7.97-percent debt. The 30-day grace period to make payment related to this issue has passed and NRG did not make the required payments. NRG is in default on these bonds.

Audrain Capital Lease In connection with NRG's acquisition of the Audrain facilities, NRG recognized a capital lease on its balance sheet within long-term debt in the amount of $239.9 million, as of Dec. 31, 2002 and 2001. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in May 2023. During the term of the lease, only interest payments are due. No principal is due until the end of the lease. In addition, NRG has recorded in notes receivable an amount of approximately $239.9 million, which represents its investment in the bonds that the county of Audrain issued to finance the project. During December 2002, NRG received a notice of a waiver of a $24.0-million interest payment due on the capital lease obligation.

LONG-TERM DEBT – SUBSIDIARY

NEO Corp. The various NEO notes are term loans. The loans are secured principally by long-term assets of NEO Landfill Gas collection system. NEO Landfill Gas is required to maintain compliance with certain covenants primarily related to incurring debt, disposing of the NEO Landfill Gas assets and affiliate transactions. On Oct. 30, 2002, NRG failed to make $3.1 million in payments under certain non-operating interest acquisition agreements. As a result, NEO Corp., a direct, wholly owned subsidiary of NRG, and NEO Landfill Gas, Inc., an indirect, wholly owned subsidiary of NRG, failed to make approximately $1.4 million in loan payments. Also, the subsidiaries of NEO Corp. and NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various agreements. NRG received an extension until November 2002 with respect to NEO Landfill Gas, Inc. to make payments under such agreements, and such payments were made during the extension period. The payments relating to NEO Corp. were not made, and the loan was due and payable on Dec. 20, 2002. A letter of credit was drawn to pay the NEO Corp. loan in full on Dec. 23, 2002. As of Dec. 31, 2002, NEO Landfill

Gas, Inc. was in default under the loan agreement dated July 6, 1998, due to the failure to meet the insurance requirements under the loan document. On Jan. 30, 2003, NRG failed to make $2.7 million in payments under certain acquisition agreements. As a result, NEO Landfill Gas, Inc. failed to make its payment due on Jan. 30, 2003, under the loan agreement and the subsidiaries of NEO Landfill Gas failed to make their payments pursuant to various agreements.

Northeast Generating LLC In February 2000, NRG Northeast Generating LLC, an indirect, wholly owned subsidiary of NRG, issued $750 million of project level senior secured bonds to refinance short-term project borrowings and for certain other purposes. The bonds are jointly and severally guaranteed by each of NRG Northeast's existing and future subsidiaries. The bonds are secured by a security interest in NRG Northeast's membership or other ownership interests in the guarantors and its rights under all intercompany notes between NRG Northeast and the guarantors. In December 2002, NRG Northeast Generating failed to make $24.7-million interest and $53.5-million principal payments. NRG Northeast Generating had a 15-day grace period to make payment. On Dec. 27, 2002, NRG made the $24.7-million interest payment due on the NRG Northeast Generating bonds but failed to make the $53.5-million principal payment. As a result, the payment default associated with its failure to make principal payments when they come due is currently in effect. NRG also failed to make a debt service reserve account cash deposit within 30 days of a credit-rating downgrade in July 2002. In addition, NRG Northeast Generating is also in default of its debt covenants because of the lapse of the 60-day grace period regarding the necessary dismissal of an involuntary bankruptcy proceeding. For these reasons, NRG Northeast Generating is in default on these notes.

NRG South Central Generating LLC In March 2000, NRG South Central Generating LLC, an indirect, wholly owned subsidiary of NRG, issued $800 million of senior secured bonds in a two-part offering to finance its acquisition of the Cajun generating facilities. The bonds are secured by a security interest in NRG Central U.S. LLC's and South Central Generating Holding LLC's membership interests in NRG South Central and NRG South Central's membership interests in Louisiana Generating and all of the assets related to the Cajun facilities, including its rights under a guarantor loan agreement and all inter-company notes between it and Louisiana Generating, and a revenue account and a debt service reserve account. On Sept. 15, 2002, NRG South Central Generating missed a $47-million principal and interest payment. The 15-day grace period to make payment related to this issue has passed, and NRG South Central Generating did not make the required payments. In January 2003, the South Central Generating bondholders unilaterally withdrew $35.6 million from the restricted revenue account, relating to the Sept. 15, 2002, interest payment and fees. On March 17, 2003, South Central bondholders were paid $34.4 million due in relation to the semi-annual interest payment, and the $12.8 million principal payment was deferred. NRG South Central remains in default on these notes.

Flinders Power Finance In September 2000, Flinders Power Finance Pty (Flinders Power), an Australian wholly owned subsidiary, entered into a 12-year AUD $150-million promissory note (US $81.4 million at September 2000). As of Dec. 31, 2002, there remains $80.5 million outstanding under this facility. In March 2002, Flinders Power entered into a 10-year AUD $165-million (US $85.4 million at March 2002) floating rate promissory note for the purpose of refurbishing the Flinders Playford generating station. As of Dec. 31, 2002, Flinders Power had drawn $18.7 million (AUD $33 million) of this facility. Upon NRG's credit-rating downgrade in 2002, there existed a potential default under these agreements related to the funding of reserve funds. Flinders continues to work with its lenders subsequent to the downgrade.

NRG Peaker Finance Company LLC In June 2002, NRG Peaker Finance Co. LLC (NRG Peaker), an indirect, wholly owned subsidiary of NRG, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds, due 2019. The bonds are secured by a pledge of membership interests in NRG Peaker and a security interest in all of its assets, which initially consisted of notes evidencing loans to the affiliate project owners. The project owners jointly and severally guaranteed the entire principal amount of the bonds and interest on such principal amount. The project owner guarantees are secured by a pledge of the membership interest in three of five project owners and a security interest in substantially all of the project owners' assets related to the peaker projects, including equipment, real property rights, contracts and permits. NRG has entered into a contingent guarantee agreement in favor of the collateral agent for the benefit of the secured parties, under which it agreed to make payments to cover scheduled principal and interest payments on the bonds and regularly scheduled payments under the interest rate swap agreement, to the extent that the net revenues from the peaker projects are insufficient to make such payments, in specified circumstances. As a result of cross-default provisions, this facility is in default. On Dec. 10, 2002, $16.0 million in interest, principal, and swap payments were made from restricted cash accounts. As a result, $319.4 million in principal remains outstanding as of Dec. 31, 2002.

LSP-Pike Energy LLC LSP-Pike Energy LLC received a loan to construct its power generation facility in Pike County, Mississippi, that was financed by the issuance of industrial revenue bonds (Series 2002). NRG Finance Co. I LLC, an affiliate of LSP-Pike Energy LLC, purchased the Series 2002 bonds. These bonds are subject to a subordination agreement between NRG Finance Co. I LLC, as purchaser, and LSP-Pike Energy LLC and Credit Suisse First Boston, as administrative agent to a senior claim. In the case of insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings, and even in the event of any proceedings for voluntary liquidation, dissolutions or other winding up of the company, the holders of the senior claims shall be entitled to receive payment in full or cash equivalents of all principal, interest, charges and fees on all senior claims before the purchaser is entitled to receive any payment on account of the principal of or interest on these bonds. As of Oct. 17, 2002, the United States Bankruptcy Court for the Southern District of Mississippi granted an order of relief to the debtor under the U.S. bankruptcy laws, thus forcing LSP-Pike Energy LLC into default and cessation of all benefits granted under the terms of the loan agreement and issuance of the bonds.

LONG-TERM DEBT – CREDIT FACILITIES

NRG has several credit facilities used for long-term financing:

(Thousands of dollars) *Facility*	*Available Line of Credit*	*Recourse to NRG*	*End Date*	*Outstanding Dec. 31, 2002*	*Rate at Dec. 31, 2002*
Revolving lines of credit					
NRG Finance Co. I LLC	$2,000,000	Yes	May 2006	$1,081,000	4.92%
Term loan facilities					
Mid-Atlantic	$580,000	No	November 2005	$409,200	3.30%
LSP Kendall Energy	$554,200	No	September 2005	$495,800	3.19%
Brazos Valley	$180,000	No	June 2008	$194,400	4.41%
McClain	$296,000	No	November 2006	$157,300	4.57%

NRG Financing Co. I LLC The NRG Finance Co. I LLC facility has been used to finance the acquisition, development and construction of power generating plants located in the United States, and to finance the acquisition of turbines for such facilities. The facility is nonrecourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility. NRG estimates the obligations to contribute equity to be approximately $819 million as of Dec. 31, 2002. At Dec. 31, 2002, interest and fees due in September 2002 were not paid, and NRG has suspended required equity contributions to the projects. Supporting construction and other contracts associated with NRG's Pike and Nelson projects were violated by NRG in September and October 2002, respectively. In November 2002, lenders to NRG accelerated the approximately $1.08 billion of debt under the construction revolver facility, rendering the debt immediately due and payable. Thus, this facility is currently in default.

LSP Kendall Energy As part of NRG's acquisition of the LS Power assets in January 2001, NRG, through its wholly owned subsidiary LSP Kendall Energy LLC, has acquired a $554.2-million credit facility. On Jan. 10, 2003, NRG received a notice of default from LSP Kendall's lenders indicating that certain events of default have taken place. By issuing this notice of default, the lenders have preserved all of their rights and remedies under the credit agreement and other credit documents. NRG is negotiating a waiver to this default notice with the creditors to LSP Kendall.

Brazos Valley In June 2001, NRG, through its wholly owned subsidiaries Brazos Valley Energy LP and Brazos Valley Technology LP, entered into a $180-million nonrecourse construction credit facility to fund the construction of the 600-megawatt Brazos Valley gas-fired, combined-cycle merchant generation facility, located in Texas. On Jan. 31, 2003, NRG consented to the foreclosure of its Brazos Valley project by its lenders. As consequence of foreclosure, NRG no longer has any interest in the Brazos Valley project. However, NRG may be obligated to infuse additional capital to fund a debt service reserve account that had never been funded, and may be obligated to make an equity infusion to satisfy a contingent equity agreement. As of Dec. 31, 2002, NRG recorded $24 million for the potential obligations.

McClain In August 2001, NRG entered into a 364-day term loan of up to $296 million. The credit facility was structured as a senior unsecured loan and was partially nonrecourse to NRG. The proceeds were used to finance the McClain generating facility acquisition. In November 2001, the credit facility was repaid from the proceeds of a $181.0-million term loan and $8.0-million working capital facility entered into by NRG McClain LLC with Westdeutsche Landesbank Girozentrale, nonrecourse to NRG. On Sept. 17, 2002, NRG McClain LLC received notice from the agent bank that the project loan was in default as a result of the downgrade of NRG and of defaults on material obligations.

8. PREFERRED STOCK

At Dec. 31, 2002, Xcel Energy had six series of preferred stock outstanding, which were callable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends. Xcel Energy can only pay dividends on its preferred stock from retained earnings absent approval of the SEC under PUHCA. See Note 12 for a description of such restrictions.

The holders of the $3.60 series preferred stock are entitled to three votes for each share held. The holders of the other preferred stocks are entitled to one vote per share. While dividends payable on the preferred stock of any series outstanding is in arrears in an amount equal to four quarterly dividends, the holders of preferred stocks, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the board of directors, and the holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of Xcel Energy's subsidiaries also authorize the issuance of preferred shares. However, at this time, there are no such shares outstanding. This chart shows data for first- and second-tier subsidiaries:

	Preferred Shares Authorized	*Par Value*	*Preferred Shares Outstanding*
Cheyenne Light, Fuel & Power Co.	1,000,000	$100.00	None
Southwestern Public Service Co.	10,000,000	$ 1.00	None
Public Service Co. of Colorado	10,000,000	$ 0.01	None

9. MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, has $100 million of 7.85-percent trust preferred securities issued and outstanding 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.

NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, has $200 million of 7.875-percent trust preferred securities issued and outstanding 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 NSP Financing I's option at $25 per share, beginning in 2002. Distributions and redemption payments are guaranteed by NSP-Minnesota.

PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, has $194 million of 7.60-percent trust preferred securities issued and outstanding 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.

The mandatorily redeemable preferred securities of subsidiary trusts are consolidated in Xcel Energy's Consolidated Balance Sheets. Distributions paid to preferred security holders are reflected as a financing cost in the Consolidated Statements of Operations, along with interest charges.

10. JOINT PLANT OWNERSHIP

The investments by Xcel Energy's subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2002, are:

(Thousands of dollars)	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NSP-Minnesota				
Sherco Unit 3	$612,643	$291,754	$ 943	59.0
PSCo				
Hayden Unit 1	$ 84,486	$ 38,429	$ 446	75.5
Hayden Unit 2	79,882	42,291	6	37.4
Hayden Common Facilities	27,339	3,300	250	53.1
Craig Units 1 and 2	59,636	31,963	258	9.7
Craig Common Facilities Units 1, 2 and 3	18,473	9,029	3,409	6.5–9.7
Transmission Facilities, including Substations	89,254	29,365	1,208	42.0–73.0
Total PSCo	$359,070	$154,377	$5,577	
NRG				
McClain	$277,566	$ 12,329	$ –	77.0
Big Cajun II Unit 3	188,758	12,275	244	58.0
Conemaugh	62,045	4,134	766	3.7
Keystone	52,905	3,543	5,039	3.7
Total NRG	$581,274	$ 32,281	$6,049	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of operating expenses for Sherco 3 is included in the applicable utility components of operating expenses. PSCo's assets include approximately 320 megawatts of jointly owned generating capacity. PSCo's share of operating expenses and construction expenditures is included in the applicable utility components of operating expenses.

NRG's share of operating expenses and construction expenditures is included in the applicable nonregulated components of operating expenses. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

11. INCOME TAXES

As discussed in Note 1 to the Consolidated Financial Statements, the tax filing status of NRG for 2002 will change from filing as a separate consolidated group, apart from the Xcel Energy consolidated group, to the NRG members filing on a stand-alone basis. On a stand-alone basis, the NRG member companies do not have the ability to recognize all tax benefits that may ultimately accrue from its losses incurred in 2002. NRG may have the ability to receive tax benefits for such losses in future periods as income is earned.

In consideration of the foreseeable effects of the NRG restructuring plan on Xcel Energy's investment in NRG, Xcel Energy has recognized the expected tax benefits from this investment as of Dec. 31, 2002. The tax benefit was estimated to be $706 million and was recorded at one of Xcel Energy's nonregulated intermediate holding companies. This benefit is based on the difference between the book and tax bases of Xcel Energy's investment in NRG.

The actual amount of tax benefit derived by Xcel Energy for its investment in NRG is dependent upon various factors, including certain factors that may be affected by the terms of any financial restructuring agreement reached with NRG's creditors. Similarly, the amount and timing of tax benefits to be recorded by NRG, related to 2002 losses, is dependent on estimated future results of NRG.

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:

	2002	*2001*	*2000*
Federal statutory rate	**35.0%**	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	**5.6**	3.6	6.0
Life insurance policies	**1.1**	(2.0)	(2.5)
Tax credits recognized	**1.5**	(6.9)	(10.7)
Equity income from unconsolidated affiliates	**0.8**	(1.7)	(2.3)
Income from foreign consolidated affiliates	**1.8**	(6.0)	1.8
Regulatory differences – utility plant items	**(0.5)**	1.9	2.4
Valuation allowance	**(46.8)**	5.8	–
Xcel Energy tax benefit on NRG	**30.7**	–	–
Nondeductible merger costs	**–**	–	3.1
Other – net	**(1.9)**	(0.5)	2.9
Total effective income tax rate	**27.3**	29.2	35.7
Extraordinary item	**–**	(0.4)	1.0
Effective income tax rate from continuing operations	**27.3%**	28.8%	36.7%

Income taxes comprise the following expense (benefit) items:

(Thousands of dollars)	*2002*	*2001*	*2000*
Current federal tax expense	**$ 114,273**	$373,710	$205,472
Current state tax expense	**21,724**	26,927	63,428
Current foreign tax expense	**18,973**	10,988	1,693
Current tax credits	**(18,067)**	(66,179)	(71,270)
Deferred federal tax expense	**(631,468)**	(24,323)	103,033
Deferred state tax expense	**(114,486)**	18,702	12,547
Deferred foreign tax expense	**(2,248)**	4,529	(578)
Deferred investment tax credits	**(16,686)**	(12,983)	(15,295)
Income tax expense (benefit) excluding extraordinary items	**(627,985)**	331,371	299,030
Tax expense (benefit) on extraordinary items	**–**	4,807	(8,549)
Total income tax expense from continuing operations	**$(627,985)**	$336,178	$290,481

As of Dec. 31, 2001, Xcel Energy management intended to reinvest the earnings of NRG's foreign operations to the extent the earnings were subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $345 million at Dec. 31, 2001. As of Dec. 31, 2002, Xcel Energy management has revised its strategy and no longer intends to indefinitely reinvest the full amount of earnings of NRG's foreign operations. However, no U.S. income tax benefit has been provided on the cumulative amount of unremitted losses of $339.7 million at Dec. 31, 2002, due to the uncertainty of realization.

Xcel Energy management intends to indefinitely reinvest the earnings of the Argentina operations of Xcel Energy International and, therefore, has not provided deferred taxes for the effects of currency devaluations.

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

(Thousands of dollars)	*2002*	*2001*
Deferred tax liabilities		
Differences between book and tax basis of property	**$2,060,450**	$2,083,965
Regulatory assets	**159,942**	155,587
Partnership income/loss	**33,739**	53,955
Unrealized gains and losses on mark-to-market transactions	**–**	9,348
Tax benefit transfer leases	**10,993**	14,765
Employee benefits and other accrued liabilities	**8,883**	16,559
Other	**78,250**	66,538
Total deferred tax liabilities	**$2,352,257**	$2,400,717
Deferred tax assets		
Xcel Energy benefit on NRG	**$ 706,000**	$ –
Book write-down (impairment of assets)	**707,183**	–
Net operating loss carryforward	**473,220**	3,867
Differences between book and tax basis of contracts	**19,806**	82,972
Deferred investment tax credits	**66,801**	72,345
Regulatory liabilities	**48,558**	66,507
Unrealized gains and losses on mark-to-market transactions	**30,707**	–
Foreign tax loss carryforwards	**16,088**	90,251
Other	**73,838**	83,484
Total deferred tax assets	**$2,142,201**	$ 399,426
Less valuation allowance	**1,077,047**	66,622
Net deferred tax liability	**$1,287,103**	$2,067,913

12. COMMON STOCK AND INCENTIVE STOCK PLANS

Common Stock and Equivalents In February 2002, Xcel Energy issued 23 million shares of common stock at $22.50 per share. In June 2002, Xcel Energy issued 25.7 million shares of common stock to complete its exchange offer for the publicly held stock of NRG. As a result of these issuances, Xcel Energy had approximately 399 million shares outstanding on Dec. 31, 2002.

In November 2002, Xcel Energy issued $230 million of 7.5-percent convertible senior notes. The senior notes are convertible into shares of Xcel Energy common stock at a conversion price of $12.33 per share. The conversion of $230 million in notes at a share price of $12.33 would be the equivalent of approximately 18.7 million shares. However, due to losses experienced in 2002, the impact of the convertible senior notes was antidilutive and, therefore, was not included in the common stock and equivalent calculation in 2002.

Other common stock equivalents included stock options, as discussed further, and NRG equity units. See discussion of NRG equity units, which are convertible to Xcel Energy common stock, at Note 7. Due to the losses experienced in 2002, these equivalents were also antidilutive and were not incorporated in the common stock and equivalents calculation in 2002.

The dilutive impacts of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

(Thousands of dollars, except per share amounts)	*2002*	*2001*	*2000*
Basic EPS calculation			
Earnings (loss) available for common	**$(2,222,232)**	$790,725	$522,587
Weighted average common stock outstanding	**382,051**	342,952	337,832
Basic earnings per share	**$ (5.82)**	$ 2.31	$ 1.54
Diluted calculation			
Earnings (loss) available for common	**$(2,222,232)**	$790,725	$522,587
Adjustments for dilutive securities	**–**	–	–
Earnings (loss) for dilutive securities	**$(2,222,232)**	$790,725	$522,587
Weighted average common stock outstanding	**382,051**	342,952	337,832
Adjustments for common stock equivalents	**–**	790	279
Weighted average common stock and equivalents	**382,051**	343,742	338,111
Diluted earnings per share	**$ (5.82)**	$ 2.30	$ 1.54

Incentive Stock Plans Xcel Energy and some of its 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 include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables that follow include awards made by us and some of our predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

Activity in stock options and performance awards for the years ended Dec. 31:

	2002		2001		2000	
(Awards in thousands)	*Awards*	*Average Price*	*Awards*	*Average Price*	*Awards*	*Average Price*
Outstanding at beginning of year	**15,214**	**$25.65**	14,259	$25.35	8,490	$25.12
Granted	**–**	**–**	2,581	25.98	6,980	25.31
Options adopted from NRG	**3,328**	**29.97**	–	–	–	–
Exercised	**(112)**	**20.27**	(1,472)	23.00	(453)	20.33
Forfeited	**(1,349)**	**28.43**	(142)	27.08	(704)	25.70
Expired	**(100)**	**28.87**	(12)	24.07	(54)	22.62
Outstanding at end of year	**16,981**	**26.29**	15,214	25.65	14,259	25.35
Exercisable at end of year	**8,993**	**$24.78**	7,154	$24.78	8,221	$24.46

	Range of Exercise Prices		
At Dec. 31, 2002	*$11.50 to $25.50*	*$25.51 to $27.00*	*$27.01 to $63.60*
Options outstanding:			
Number outstanding	4,449,827	7,878,856	4,652,424
Weighted average remaining contractual life (years)	4.7	7.3	7.4
Weighted average exercise price	$19.87	$26.29	$32.44
Options exercisable:			
Number exercisable	4,091,097	3,158,956	1,742,579
Weighted average exercise price	$20.17	$26.46	$32.57

Certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally from two to three years from the date of grant. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment. Restricted shares have a value equal to the market trading price of Xcel Energy's stock at the grant date. We granted 50,083 restricted shares in 2002, when the grant-date market price was $22.83, 21,774 restricted shares in 2001, when the grant-date market price was $26.06 and 58,690 restricted shares in 2000, when the grant-date market price was $19.25. 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 was not 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 our 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 No. 123 method of accounting, earnings would have been the same for 2002 and reduced by approximately 1 cent per share for 2001 and 2 cents per share for 2000.

The weighted-average fair value of options granted, and the assumptions used to estimate such fair value on the date of grant using the Black-Scholes Option Pricing Model, were as follows:

	2002*	2001	2000
Weighted-average fair value per option share at grant date	–	$2.13	$2.57
Expected option life	–	3–5 years	3–5 years
Stock volatility	–	18%	15%
Risk-free interest rate	–	3.8–4.8%	5.3–6.5%
Dividend yield	–	4.9–5.8%	5.4–7.5%

** There were no options granted in 2002.*

Common Stock Dividends Per Share Historically, we have paid quarterly dividends to our shareholders. For each quarter in 2001 and for the first two quarters of 2002, we paid dividends to our shareholders of $0.375 per share. In the third and fourth quarters of 2002, we paid dividends of $0.1875 per share. In making the decision to reduce the dividend, the board of directors considered several factors, including the goal of funding customer growth in our core business through internal cash flow and reducing our reliance on debt and equity financings. The board of directors also compared our dividend to its utility earnings and to the dividend payout of comparable utilities. Dividends on our common stock are paid as declared by our board of directors.

Dividend and Other Capital-Related Restrictions Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of Xcel

Energy were a deficit of $101 million at Dec. 31, 2002, and, accordingly, dividends cannot be declared until earnings in 2003 are sufficient to eliminate this deficit or Xcel Energy is granted relief under the PUHCA. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until Sept. 30, 2003. Xcel Energy did not declare a dividend on its common stock during the first quarter of 2003. It is not known when or if the SEC will act on this request.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, i.e., not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at Dec. 31, 2002, was 85 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

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 $825 million in additional cash dividends on common stock at Dec. 31, 2002.

Under PUHCA, Xcel Energy is also restricted from financing activities when its common equity to total capitalization ratio is less than 30 percent. As a result of significant asset impairments at NRG, Xcel Energy's common equity ratio fell below 30 percent during 2002. However, the SEC approved Xcel Energy's request to allow certain financing transactions through March 31, 2003, so long as its common equity ratio, as reported in its most recent quarterly or annual report with the SEC and as adjusted for pending subsequent items that affect capitalization, was at least 24 percent of its total capitalization. At Dec. 31, 2002, and as adjusted for subsequent items that affect capitalization, Xcel Energy's common equity ratio was 23 percent of its total capitalization. As a result, Xcel Energy could not finance at Dec. 31, 2002, absent SEC approval.

Stockholder Protection Rights Agreement In June 2001, Xcel Energy adopted a Stockholder Protection Rights Agreement. Each share of Xcel Energy's common stock includes one shareholder protection right. Under the agreement's principal provision, if any person or group acquires 15 percent or more of Xcel Energy's outstanding common stock, all other shareholders of Xcel Energy would be entitled to buy, for the exercise price of $95 per right, common stock of Xcel Energy having a market value equal to twice the exercise price, thereby substantially diluting the acquiring person's or group's investment. The rights may cause substantial dilution to a person or group that acquires 15 percent or more of Xcel Energy's common stock. The rights should not interfere with a transaction that is in the best interests of Xcel Energy and its shareholders because the rights can be redeemed prior to a triggering event for $0.01 per right.

13. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 51 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2002, NSP-Minnesota had 2,246 and NSP-Wisconsin had 419 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 2,193 bargaining employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 757 bargaining employees covered under a collective-bargaining agreement, which expires in October 2005.

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

Xcel Energy's 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. The target range for our pension asset allocation is 75 to 80 percent with equity investments, 5 to 10 percent with fixed income investments, no cash investments and 10 to 15 percent with nontraditional investments, such as real estate and timber ventures. At Dec. 31, 2002, the actual pension portfolio mix was 68 percent equity, 16 percent fixed income, 4 percent cash investments and 12 percent nontraditional investments.

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

(Thousands of dollars)	*2002*	*2001*
Change in Benefit Obligation		
Obligation at Jan. 1	**$2,409,186**	$2,254,138
Service cost	**65,649**	57,521
Interest cost	**172,377**	172,159
Acquisitions	**7,848**	–
Plan amendments	**3,903**	2,284
Actuarial loss	**65,763**	108,754
Settlements	**(994)**	–
Special termination benefits	**4,445**	–
Benefit payments	**(222,601)**	(185,670)
Obligation at Dec. 31	**$2,505,576**	$2,409,186
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$3,267,586**	$3,689,157
Actual return on plan assets	**(404,940)**	(235,901)
Employer contributions – acquisitions	**912**	–
Settlements	**(994)**	–
Benefit payments	**(222,601)**	(185,670)
Fair value of plan assets at Dec. 31	**$2,639,963**	$3,267,586
Funded Status of Plans at Dec. 31		
Net asset	**$ 134,387**	$ 858,400
Unrecognized transition asset	**(2,003)**	(9,317)
Unrecognized prior service cost	**224,651**	242,313
Unrecognized (gain) loss	**182,927**	(712,571)
Net pension amounts recognized on Consolidated Balance Sheets	**$ 539,962**	$ 378,825
Prepaid pension asset recorded	**$ 466,229**	$ 378,825
Intangible asset recorded – prior service costs	**$ 6,943**	$ –
Minimum pension liability recorded	**$ (106,897)**	$ –
Accumulated other comprehensive income recorded – pretax	**$ 173,687**	$ –
Significant Assumptions		
Discount rate for year-end valuation	**6.75%**	7.25%
Expected average long-term increase in compensation level	**4.00%**	4.50%
Expected average long-term rate of return on assets	**9.50%**	9.50%

The discount rate and compensation increase assumptions above affect the succeeding year's pension costs. The rate of return assumption affects the current year's pension cost. The return assumption used for 2003 pension cost calculations will be 9.25 percent. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The cost calculation uses a market-related valuation of pension assets, which reduces year-to-year volatility by recognizing the differences between assumed and actual investment returns over a five-year period.

NRG offers another noncontributory, defined benefit pension plan sponsored by one of its affiliates. For the year ended Dec. 31, 2002, the total assets of this plan were $20 million, and its benefit obligation was $30 million. The pension liability recorded by NRG for this plan was $12 million, and its annual pension cost was $2 million.

During 2002, one of Xcel Energy's pension plans, other than the NRG plan just described, became underfunded, with projected benefit obligations of $590 million exceeding plan assets of $452 million on Dec. 31, 2002. All other Xcel Energy plans, excluding the NRG plan just described, in the aggregate had plan assets of $2,188 million and projected benefit obligations of $1,916 million on Dec. 31, 2002. A minimum pension liability of $107 million was recorded related to the underfunded plan as of that date. A corresponding reduction in Accumulated Other Comprehensive Income, a component of Stockholders' Equity, was also recorded by Xcel Energy, as previously recorded prepaid pension assets were reduced to record the minimum liability. Net of the related deferred income tax effects of the adjustments, total Stockholders' Equity was reduced by $108 million at Dec. 31, 2002, due to the minimum pension liability for the underfunded plan.

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

(Thousands of dollars)	*2002*	*2001*	*2000*
Service cost	**$ 65,649**	$ 57,521	$ 59,066
Interest cost	**172,377**	172,159	172,063
Expected return on plan assets	**(339,932)**	(325,635)	(292,580)
Curtailment	**–**	1,121	–
Amortization of transition asset	**(7,314)**	(7,314)	(7,314)
Amortization of prior service cost	**22,663**	20,835	19,197
Amortization of net gain	**(69,264)**	(72,413)	(60,676)
Net periodic pension cost (credit) under SFAS No. 87	**$(155,821)**	$(153,726)	$(110,244)
Credits not recognized due to effects of regulation	**71,928**	76,509	49,697
Net benefit cost (credit) recognized for financial reporting	**$ (83,893)**	$ (77,217)	$ (60,547)

Xcel Energy also 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 2002, $29 million in 2001 and $24 million in 2000.

Until May 6, 2002, Xcel Energy had a leveraged employee stock ownership plan (ESOP) that covered substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy made contributions to this noncontributory, defined contribution plan to the extent it realized tax savings from dividends paid on certain ESOP shares. ESOP contributions had no material effect on Xcel Energy earnings because the contributions were essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocated leveraged ESOP shares to participants when it repaid ESOP loans with dividends on stock held by the ESOP.

In May 2002, the ESOP was terminated and its assets were combined into the Xcel Energy retirement savings 401(k) plan. Starting with the 2003 plan year, the ESOP component of the 401(k) plan will no longer be leveraged.

Xcel Energy's leveraged ESOP held no shares of Xcel Energy common stock at the end of 2002, 10.7 million shares of Xcel Energy common stock at May 6, 2002, 10.5 million shares of Xcel Energy common stock at the end of 2001 and 12 million shares of Xcel Energy common stock at the end of 2000. Xcel Energy excluded the following average number of uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2002, 0.9 million in 2001 and 0.7 million in 2000. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and will be used by Xcel Energy for the 2002 employer matching contribution to its 401(k) plan.

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 former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. However, employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106 – "Employers' Accounting for Postretirement Benefits Other Than Pension," 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 No. 106. PSCo transitioned to full accrual accounting for SFAS No. 106 costs between 1993 and 1997, consistent with the accounting requirements for rate-regulated enterprises. The Colorado jurisdictional SFAS No. 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 No. 106 costs, with regulatory differences fully amortized prior to 1997.

Certain state agencies that regulate Xcel Energy's utility subsidiaries have also issued guidelines related to the funding of SFAS No. 106 costs. SPS is required to fund SFAS No. 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo is required to fund SFAS No. 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Minnesota and Wisconsin retail regulators required external funding of accrued SFAS No. 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 for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table:

(Thousands of dollars)	2002	2001
Change in Benefit Obligation		
Obligation at Jan. 1	**$687,455**	$576,727
Service cost	**7,173**	6,160
Interest cost	**50,135**	46,579
Acquisitions	**773**	3,212
Plan amendments	**–**	(278)
Plan participants' contributions	**5,755**	3,517
Actuarial loss	**61,276**	100,386
Special termination benefits	**(173)**	–
Benefit payments	**(44,419)**	(48,848)
Obligation at Dec. 31	**$767,975**	$687,455
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$242,803**	$223,266
Actual return on plan assets	**(13,632)**	(3,701)
Plan participants' contributions	**5,755**	3,517
Employer contributions	**60,476**	68,569
Benefit payments	**(44,419)**	(48,848)
Fair value of plan assets at Dec. 31	**$250,983**	$242,803
Funded Status at Dec. 31		
Net obligation	**$516,992**	$444,652
Unrecognized transition asset (obligation)	**(169,328)**	(186,099)
Unrecognized prior service cost	**10,904**	12,812
Unrecognized gain (loss)	**(206,601)**	(134,225)
Accrued benefit liability recorded	**$151,967**	$137,140
Significant Assumptions		
Discount rate for year-end valuation	**6.75%**	7.25%
Expected average long-term rate of return on assets (pretax)	**8.0–9.0%**	9.0%

The assumed health care cost trend rate for 2002 for most Xcel Energy plans is approximately 8 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. The assumed health care cost trend rate for 2002 for plans of four of NRG's affiliates is approximately 12 percent, decreasing gradually to 5.5 percent in 2009 and remaining level thereafter. A 1-percent change in the assumed health care cost trend rate would have the following effects:

(Thousands of dollars)	
1-percent increase in APBO components at Dec. 31, 2002	$ 79,028
1-percent decrease in APBO components at Dec. 31, 2002	$(65,755)
1-percent increase in service and interest components of the net periodic cost	$ 6,285
1-percent decrease in service and interest components of the net periodic cost	$ (5,181)

The components of net periodic postretirement benefit cost are:

(Thousands of dollars)	2002	2001	2000
Service cost	**$ 7,173**	$ 6,160	$ 5,679
Interest cost	**50,135**	46,579	43,477
Expected return on plan assets	**(21,030)**	(18,920)	(17,902)
Amortization of transition obligation	**16,771**	16,771	16,773
Amortization of prior service cost (credit)	**(1,130)**	(1,235)	(1,211)
Amortization of net loss (gain)	**5,380**	1,457	915
Net periodic postretirement benefit cost (credit) under SFAS No. 106	**57,299**	50,812	47,731
Additional cost recognized due to effects of regulation	**4,043**	3,738	6,641
Net cost recognized for financial reporting	**$61,342**	$54,550	$54,372

14. EQUITY INVESTMENTS

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, because the ownership structure prevents Xcel Energy from exercising a controlling influence over the operating and financial policies of the projects. 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	*Entity Form*	*Xcel Energy Owner Functions*	*Geographic Area*	*Dec. 31, 2002 Economic Interest*
Loy Yang Power A	Partnership	None	Australia	25.37%
Gladstone Power Station	Joint Venture	Operator	Australia	37.50%
MIBRAG GmbH	Partnership	None	Europe	50.00%
West Coast Power	Partnership	Operator	USA	50.00%
Lanco Kondapalli Power *(1)*	Partnership	Operator	India	30.00%
Rocky Road Power	Partnership	Operator	USA	50.00%
Schkopau	Tenants in Common	None	Europe	41.67%
ECK Generating *(1)*	Partnership	Operator	Czech Republic	44.50%
Commonwealth Atlantic			USA	50.00%
Mustang	Joint Venture	None	USA	50.00%
Quixx Linden L.P.	General/Limited Partnership	Operator	USA	50.00%
Borger Energy L.P.	General/Limited Partnership	Operator	USA	45.00%
Various affordable housing limited partnerships	Limited Partnerships	Various	USA	20.00%–99.99%

(1) Pending disposition at Dec. 31, 2002

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)	***2002***	*2001*	*2000*
Operating revenues	**$2,516**	$3,583	$4,664
Operating income (loss)	**$ 137**	$ 442	$ 464
Net income (loss)	**$ 111**	$ 422	$ 447
Xcel Energy's equity earnings of unconsolidated affiliates	**$ 72**	$ 217	$ 183

FINANCIAL POSITION

(Millions of dollars)	***2002***	*2001*
Current assets	**$1,102**	$1,478
Other assets	**7,155**	7,396
Total assets	**$8,257**	$8,874
Current liabilities	**$1,108**	$1,229
Other liabilities	**4,087**	4,841
Equity	**3,062**	2,804
Total liabilities and equity	**$8,257**	$8,874
Xcel Energy's share of undistributed retained earnings	**$ 466**	$ 449
Xcel Energy equity in underlying net assets	**$1,285**	$1,099
Difference – other than temporary write-downs, capitalized project costs and other	**(284)**	98
Xcel Energy's investment in unconsolidated affiliates (per balance sheet)	**$1,001**	$1,197

West Coast Power In 2001, Xcel Energy had a significant investment in West Coast Power, LLC, through NRG, as defined by applicable SEC regulations, and accounted for its investments using the equity method. The following is summarized pretax financial information for West Coast Power:

RESULTS OF OPERATIONS

(Millions of dollars)	*2001*
Operating revenues	$1,562
Operating income (loss)	$ 345
Net income (loss)	$ 326

FINANCIAL POSITION

(Millions of dollars)	*2001*
Current assets	$ 401
Other assets	659
Total assets	$1,060
Current liabilities	$ 138
Other liabilities	269
Equity	653
Total liabilities and equity	$1,060

Yorkshire Power During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power to Innogy Holdings plc. As a result of this sales agreement, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001. In April 2001, Xcel Energy closed the sale of Yorkshire Power. Xcel Energy had retained an interest of approximately 5.25 percent in Yorkshire Power to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Xcel Energy received approximately $366 million for the sale, which approximated the book value of Xcel Energy's investment. On Aug. 28, 2002, Xcel Energy sold its remaining 5.25-percent interest in Yorkshire Power at slightly less than book value.

15. EXTRAORDINARY ITEMS

SPS In the second quarter of 2000, SPS discontinued regulatory accounting under SFAS No. 71 for the generation portion of its business due to the issuance of a written order by the Public Utility Commission of Texas (PUCT) in May 2000, addressing the implementation of electric utility restructuring. SPS' transmission and distribution business continued to meet the requirements of SFAS No. 71, as that business was expected to remain regulated. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs, totaling approximately $19.3 million. This resulted in an after-tax extraordinary charge of approximately $13.7 million. 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 first mortgage bonds. The first mortgage bonds were defeased to facilitate the legal separation of generation, transmission and distribution assets, which was expected to eventually occur in 2001 under restructuring requirements in effect in 2000.

In March 2001, the state of New Mexico enacted legislation that amended its Electric Utility Restructuring Act of 1999 and delayed customer choice until 2007. SPS has requested recovery of its costs incurred to prepare for customer choice in New Mexico. A decision on this and other matters is pending before the New Mexico Public Regulation Commission. SPS expects to receive future regulatory recovery of these costs.

In June 2001, the governor of Texas signed legislation postponing the deregulation and restructuring of SPS until at least 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition beginning in Texas in January 2002. Under the amended legislation, prior PUCT orders issued in connection with the restructuring of SPS are considered null and void. In addition, under the new legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before Sept. 1, 2001, to comply with SB-7.

As a result of these recent legislative developments, SPS reapplied the provisions of SFAS No. 71 for its generation business during the second quarter of 2001. More than 95 percent of SPS' retail electric revenues are from operations in Texas and New Mexico. Because of the delays to electric restructuring passed by Texas and New Mexico, SPS' previous plans to implement restructuring, including the divestiture of generation assets, have been abandoned. Accordingly, SPS will now continue to be subject to rate regulation under traditional cost-of-service regulation, consistent with its past accounting and ratemaking practices for the foreseeable future, until at least 2007.

During the fourth quarter of 2001, SPS completed a $500-million, medium-term debt financing with the proceeds used to reduce short-term borrowings that had resulted from the 2000 defeasance. In its regulatory filings and communications, SPS proposed to amortize its defeasance costs over the five-year life of the refinancing, consistent with historical ratemaking, and has requested incremental rate recovery of $25 million of other restructuring costs in Texas and New Mexico. These nonfinancing restructuring costs have been deferred and are being amortized consistent with rate recovery. Based on these 2001 events, management's expectation of rate recovery of prudently incurred costs and the corresponding reduced uncertainty surrounding the financial impacts of the delay in restructuring, SPS restored certain regulatory assets totaling $17.6 million as of Dec. 31, 2001, and reported related after-tax extraordinary income of $11.8 million, or 3 cents per share. Regulatory assets previously written off in 2000 were restored only for items currently being recovered in rates and items where future rate recovery is considered probable.

PSCo During 2001, PSCo's subsidiary, 1480 Welton, Inc., redeemed its long-term debt and in doing so incurred redemption premiums and other costs of $2.5 million, or $1.5 million after tax. These items are reported as an Extraordinary Item on Xcel Energy's Consolidated Statement of Operations.

16. FINANCIAL INSTRUMENTS

FAIR VALUES

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

(Thousands of dollars)	*2002* Carrying Amount	*2002* Fair Value	*2001* Carrying Amount	*2001* Fair Value
Mandatorily redeemable preferred securities of subsidiary trusts	**$ 494,000**	**$ 463,348**	$ 494,000	$ 486,270
Long-term investments	**$ 653,208**	**$ 651,443**	$ 619,976	$ 620,703
Notes receivable, including current portion	**$ 996,167**	**$ 996,167**	$ 782,079	$ 782,079
Long-term debt, including current portion	**$14,306,509**	**$12,172,059**	$11,948,527	$11,955,741

The carrying amount of cash, cash equivalents and short-term investments 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 notes receivable is based on expected future cash flows discounted at market interest rates. The balance in notes receivable consists primarily of fixed rate, from 4.75 to 19.5 percent, and variable rate notes that mature between 2003 and 2024. Notes receivable include a $366-million direct financing lease related to a long-term sales agreement for NRG's Schkopau project, and other notes related to projects at NRG that are generally secured by equity interests in partnerships and joint ventures. 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, 2002 and 2001. These fair value estimates have not been comprehensively revalued for purposes of these Consolidated Financial Statements since that date, and current estimates of fair values may differ significantly from the amounts presented herein.

GUARANTEES

Xcel Energy provides various guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral. On Dec. 31, 2002, Xcel Energy had the following amount of guarantee and exposure under these guarantees:

(Millions of dollars) Nature of Guarantee	Guarantor	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
Guarantee performance and payment of surety bonds for itself and its subsidiaries	Xcel Energy *(d)*	$342.7	$5.6	2003, 2004 2005, 2007 and 2012	*(b)*	$10.0
Guarantee performance and payment of surety bonds for those subsidiaries	Various subsidiaries *(e)*	$493.8	$116.0	2003, 2004 and 2005	*(b)*	N/A
Guarantees made to facilitate e prime's natural gas acquisition, marketing and trading operations	Xcel Energy	$264.0	$88.0	Continuous	*(a)*	N/A
Guarantees for NRG liabilities associated with power marketing obligations, fuel purchasing transactions and hedging activities	Xcel Energy	$219.5	$96.3	Latest expiration is Dec. 31, 2003	*(a)*	N/A
Guarantee of payment of notes issued by Guardian Pipeline, LLC, of which Viking is one of three partners	Xcel Energy	$60.0	$60.0	Terminated Jan. 17, 2003	*(a)*	N/A
Two guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements	Xcel Energy	$26.5	$1.7	2011 and 2013	*(a)*	N/A
Construction contract performance guarantee of Utility Engineering subsidiaries	Xcel Energy	$25.0	$25.0	July 1, 2003	*(c)*	N/A
Guarantee for obligations of a customer in connection with an electric sale agreement	SPS *(f)*	$17.7	$11.0	September 2003	*(a)*	Electric transmission system
Guarantees related to energy conservation projects in which Planergy has guaranteed certain energy savings to the customer	Xcel Energy	$26.7	$26.7	Expired Jan. 1, 2003	N/A	N/A
Guarantee for payments related to energy or financial transactions for XERS Inc., a nonregulated subsidiary of Xcel Energy	Xcel Energy	$11.1	$4.1	Continuous	*(a)*	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$6.2	$6.2	Latest expiration in 2007	*(a)*	Security interest in underlying receivable agreements
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$16.4	$5.4	Continuous	*(a)*	N/A

(a) Nonperformance and/or nonpayment

(b) Failure of Xcel Energy or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(c) Failure to meet emission compliance at relevant facility

(d) $5.6-million exposure is related to $265 million of performance bonds associated with a single construction project in which Utility Engineering is participating. On Dec. 31, 2002, this project was 93-percent complete, and is expected to be fully complete in April 2003. An estimate of exposure for the remaining bonds cannot be determined as these are largely bonds posted for the benefit of various municipalities relating to the normal course of business activities.

(e) $116-million exposure is related to $491 million of performance bonds associated with three construction projects in which Utility Engineering is participating. An estimate of exposure for the remaining bonds cannot be determined as these are largely bonds posted for the benefit of various municipalities relating to the normal course of business activities. Xcel Energy is not obligated under these agreements.

(f) SPS would hold title to the collateral and would not be required to transfer the ownership of the additional transmission related facilities to the customer. SPS would also have access to the customer sinking fund account, which is approximately $6.7 million.

Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures, in the event that Standard & Poor's or Moody's downgrade Xcel Energy's credit rating below investment grade. In the event of a downgrade, Xcel Energy would expect to meet its collateral obligations with a combination of cash on hand and, upon receipt of an SEC order permitting such actions, utilization of credit facilities and the issuance of securities in the capital markets.

NRG is directly liable for the obligations of certain of its project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. In addition, in connection with the purchase and sale of fuel emission credits and power generation products to and from third parties with respect to the operation of some of NRG's generation facilities in the United States, NRG may be required to guarantee a portion of the obligations of certain of its subsidiaries. As of Dec. 31, 2002, NRG's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $374 million.

In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of Dec. 31, 2002, was approximately $342.7 million, of which $6.4 million relates to NRG. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total indemnification.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

The following discussion briefly describes the derivatives of Xcel Energy and its subsidiaries and discloses the respective fair values at Dec. 31, 2002 and 2001. For more detailed information regarding derivative financial instruments and the related risks, see Note 17 to the Consolidated Financial Statements.

Interest Rate Swaps On Dec. 31, 2002, NRG had interest rate swaps outstanding with a notional amount of approximately $1.7 billion. The fair value of those swaps on Dec. 31, 2002, was a liability of approximately $41 million. Other subsidiaries of Xcel Energy also had interest rate swaps outstanding with a notional amount of approximately $100 million, and a fair value that was a liability of approximately $12 million, at Dec. 31, 2002.

As of Dec. 31, 2001, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $2.5 billion. The fair value of the swaps as of Dec. 31, 2001, was a liability of approximately $92 million.

Electric Trading Operations Xcel Energy participates in the trading of electricity as a commodity. This trading includes forward contracts, futures and options. Xcel Energy makes purchases and sales at existing market points or combines purchases with available transmission to make sales at other market points. Options and hedges are used to either minimize the risks associated with market prices, or to profit from price volatility related to our purchase and sale commitments.

Beginning with the third quarter of 2002, Xcel Energy has presented the results of its electric trading activity using the net accounting method. The Consolidated Statements of Operations for 2001 and 2000 have been reclassified to be consistent. In earlier presentations, the gross accounting method was used. All financial derivative contracts and contracts that do not include physical delivery are recorded at the amount of the gain or loss received from the contract. The mark-to-market adjustments for these transactions are appropriately reported in the Consolidated Statements of Operations in Electric and Gas Trading Revenues.

Regulated Operations Xcel Energy's regulated energy marketing operation uses a combination of electricity and natural gas purchase for resale futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2002, the notional value of these contracts was a liability of approximately $64.3 million. The fair value of these contracts as of Dec. 31, 2002, was an asset of approximately $33.3 million.

Nonregulated Operations Xcel Energy's nonregulated operations use a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2002, the notional value of these contracts was approximately $253.8 million. The fair value of these contracts as of Dec. 31, 2002, was an asset of approximately $69.3 million.

Foreign Currency Xcel Energy and its subsidiaries have two foreign currency swaps to hedge or protect foreign currency denominated cash flows. At Dec. 31, 2002 and 2001, the net notional amount of these contracts was approximately $3 million and $46.3 million, respectively. The fair value of these contracts as of Dec. 31, 2002 and 2001, was a liability of approximately $0.3 million and $2.4 million, respectively.

LETTERS OF CREDIT

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one or two years, 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, 2002, there were $154.6 million in letters of credit outstanding, including $110.0 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.

17. DERIVATIVE VALUATION AND FINANCIAL IMPACTS

USE OF DERIVATIVES TO MANAGE RISK

Business and Operational Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation, retail distribution and energy trading operations. In certain jurisdictions, purchased power expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, Xcel Energy and its subsidiaries are exposed to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, we recover purchased power expenses and natural gas costs based on fixed price limits or under established sharing mechanisms.

Commodity price risk is managed by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil, and derivative financial instruments. Xcel Energy's risk management policy allows us to manage the market price risk within each rate-regulated operation to the extent such exposure exists. Management is limited under the policy to enter into only transactions that manage market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas and electricity we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments and physical contracts is done consistently with the local jurisdictional cost recovery mechanism.

Xcel Energy and its subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. Xcel Energy manages this market price risk by entering into firm power sales agreements for approximately 55 to 75 percent of its electric capacity and energy from each generation facility, using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed-priced electric energy requirements. Xcel Energy's risk management policy allows us to manage the market price risks and provides guidelines for the level of price risk exposure that is acceptable within our operations.

Xcel Energy is exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from our equity method investments that own electric operations. Xcel Energy manages this market price risk through our involvement with the management committee or board of directors of each of these ventures. Our risk management policy does not cover the activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk Xcel Energy and its subsidiaries are exposed to fluctuations in interest rates where we enter into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to the volatility of cash flows for interest and result in primarily fixed-rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy's risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

Currency Exchange Risk Xcel Energy and its subsidiaries have certain investments in foreign countries exposing us to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. Xcel Energy manages its exposure to changes in foreign currency by entering into derivative instruments as determined by management. Our risk management policy provides for this risk management activity.

Trading Risk Xcel Energy and its subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Xcel Energy's risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by our risk management committee made up of management personnel not involved in the trading operations.

DERIVATIVES AS HEDGES

2001 Accounting Change On Jan. 1, 2001, Xcel Energy and its subsidiaries adopted SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activities." This statement requires that all derivative instruments as defined by SFAS No. 133 be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the statement of operations, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting.

A fair value hedge requires that the effective portion of the change in the fair value of a derivative instrument be offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the offsetting gain or loss on the hedged item to be reported in an earlier period to offset the gain or loss on the derivative instrument. A cash flow hedge requires that the effective portion of the change in the fair value of a derivative instrument be recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized currently in earnings.

Xcel Energy and its subsidiaries formally document hedge relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. Derivatives are recorded in the balance sheet at fair value. Xcel Energy and its subsidiaries also formally assess, both at inception and at least quarterly thereafter, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

FINANCIAL IMPACTS OF DERIVATIVES

The impact of the components of SFAS No. 133 on Xcel Energy's Other Comprehensive Income, included in Stockholders' Equity, are detailed in the following table:

(Millions of dollars)

Net unrealized transition loss at adoption, Jan. 1, 2001	$(28.8)
After-tax net unrealized gains related to derivatives accounted for as hedges	43.6
After-tax net realized losses on derivative transactions reclassified into earnings	19.4
Accumulated other comprehensive income related to SFAS No. 133 at Dec. 31, 2001	$34.2
After-tax net unrealized losses related to derivatives accounted for as hedges	(68.3)
After-tax net realized losses on derivative transactions reclassified into earnings	28.8
Acquisition of NRG minority interest	27.4
Accumulated other comprehensive income related to SFAS No. 133 at Dec. 31, 2002	$22.1

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as a separate line item noted as "Derivative Instruments Valuation" for assets and liabilities, as well as current and noncurrent.

Cash Flow Hedges Xcel Energy and its subsidiaries enter into derivative instruments to manage exposure to changes in commodity prices. These derivative instruments take the form of fixed-price, floating-price or index sales, or purchases and options, such as puts, calls and swaps. These derivative instruments are designated as cash flow hedges for accounting purposes, and the changes in the fair value of these instruments are recorded as a component of Other Comprehensive Income. At Dec. 31, 2002, Xcel Energy had various commodity-related contracts extending through 2018. Amounts deferred in Other Comprehensive Income are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the use of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings during 2003 net gains from Other Comprehensive Income of approximately $12.9 million.

Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively fix the interest payments on certain floating rate debt obligations. These derivative instruments are designated as cash flow hedges for accounting purposes, and the change in the fair value of these instruments is recorded as a component of Other Comprehensive Income. Xcel Energy expects to reclassify into earnings during 2003 net losses from Other Comprehensive Income of approximately $13.4 million.

Hedge effectiveness is recorded based on the nature of the item being hedged. Hedging transactions for the sales of electric energy are recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs, and hedging transactions for interest rate swaps are recorded as a component of interest expense.

Hedges of Foreign Currency Exposure of a Net Investment in Foreign Operations To preserve the U.S. dollar value of projected foreign currency cash flows, Xcel Energy, through NRG, may hedge, or protect, those cash flows if appropriate foreign hedging instruments are available.

Derivatives Not Qualifying for Hedge Accounting Xcel Energy and its subsidiaries have trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Operations. All derivative instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Operations.

Normal Purchases or Normal Sales Xcel Energy and its subsidiaries enter into fixed-price contracts for the purchase and sale of various commodities for use in its business operations. SFAS No. 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented as normal and exempted from the accounting and reporting requirements of SFAS No. 133.

Xcel Energy evaluates all of its contracts within the regulated and nonregulated operations when such contracts are entered to determine if they are derivatives and if so, if they qualify and meet the normal designation requirements under SFAS No. 133. None of the contracts entered into within the trading operation are considered normal.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

18. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

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, 2002, NSP-Minnesota had loaded 17 of the containers. 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.

Other commitments established by the Legislature included 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.

See additional discussion of the current operating contingency related to the spent fuel storage facilities under Operating Contingency.

Capital Commitments As discussed in Liquidity and Capital Resources under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2002, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately $1.5 billion in 2003, $1.2 billion in 2004 and $1.3 billion in 2005.

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.

Support and Capital Subscription Agreement In May 2002, Xcel Energy and NRG entered into a support and capital subscription agreement pursuant to which Xcel Energy agreed under certain circumstances to provide up to $300 million to NRG. Xcel Energy has not to date provided funds to NRG under this agreement. However, Xcel Energy is willing to make a contribution of $300 million if the restructuring plan discussed earlier is approved by the creditors. See additional discussion of NRG restructuring at Note 4.

Leases Our subsidiaries lease a variety of equipment and facilities used in the normal course of business. Some of these leases qualify as capital leases and are accounted for accordingly. The capital leases expire between 2002 and 2025. The net book value of property under capital leases was approximately $624 million and $605 million at Dec. 31, 2002 and 2001, 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.

The remainder of the leases, primarily real estate leases and leases of coal-hauling railcars, trucks, cars and power-operated equipment, are accounted for as operating leases. Rental expense under operating lease obligations was approximately $86 million, $58 million and $56 million for 2002, 2001 and 2000, respectively.

Future commitments under operating and capital leases are:

(Millions of dollars)	*Operating Leases*	*Capital Leases*
2003	$ 66	$ 83
2004	64	80
2005	61	78
2006	58	75
2007	51	73
Thereafter	86	1,030
Total minimum obligation		$1,419
Interest		(795)
Present value of minimum obligation		$ 624

Technology Agreement We have a contract that extends through 2011 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at our option, although there are financial penalties for early termination. In 2002, we paid IBM $131.9 million under the contract and $26 million for other project business. The contract also commits us to pay a minimum amount each year from 2002 through 2011.

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 2003 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.3 billion of coal, $122.2 million of nuclear fuel and $1.6 billion of natural gas, including $1.2 billion of natural gas storage and 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.

Purchased Power Agreements The utility and nonregulated 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, SPS and certain nonregulated subsidiaries have various pay-for-performance contracts with expiration dates through the year 2050. 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.

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. This agreement was extended through a new agreement during 2002 to include the period starting May 2005 through April 2015. The cost of the agreement for this extended period is based on a base price, which was established from May 2001 through April 2002 and will be escalated by the change in the United States gross national product to reflect the current year. 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 9 percent of NSP-Minnesota's 2002 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, 2002, the estimated future payments for capacity that the utility and nonregulated subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Thousands of dollars)	*Total*
2003	$ 528,978
2004	548,173
2005	549,261
2006	540,245
2007 and thereafter	5,067,551
Total	$7,234,208

ENVIRONMENTAL CONTINGENCIES

We are subject to regulations covering air and water quality, land use, 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 cost of building and operating our facilities. This includes NRG, which is subject to regional, federal and international environmental regulation.

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, 2002, 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 environmental remediation 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 when 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 PRPs and the identification of new environmental cleanup sites.

We revise our estimates as facts become known but, at Dec. 31, 2002, our liability for the cost of remediating sites, including NRG, for which an estimate was possible was $49 million, of which $11 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

– insurance coverage;
– other parties that have contributed to the contamination; and
– 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.

Approximately $15 million of the long-term liability and $4 million of the current liability relate to a U.S. Department of Energy 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 19 to the Consolidated Financial Statements for further discussion of nuclear obligations.

Ashland MGP Site 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 Environmental Protection Agency (EPA) and WDNR have not yet selected the method of remediation to use at the site. 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 determine our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability of $19 million for its estimate of its share of the cost of remediating the portion of the Ashland site that it owns, using information available to date and 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.

As an interim action, Xcel Energy proposed, and the EPA and WDNR have approved, a coal tar removal/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. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the EPA in determining which sites require further investigation. Resolution of Ashland remediation issues is not expected until 2004 or 2005.

NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site.

Other MGP Sites NSP-Minnesota has investigated and remediated MGP sites in Minnesota and North Dakota. The MPUC allowed NSP-Minnesota to defer, rather than immediately expense, certain remediation costs of four active remediation sites in 1994. This deferral accounting treatment may be used to accumulate costs that regulators might allow us to recover from our customers. The costs are deferred as a regulatory asset until recovery is approved, and then the regulatory asset is expensed over the same period as the regulators have allowed us to collect the related revenue from our customers. In September 1998, the MPUC allowed the recovery of a portion of these MGP site remediation costs in natural gas rates. Accordingly, NSP-Minnesota has been amortizing the related deferred remediation costs to expense. In 2001, the North Dakota Public Service Commission allowed the recovery of part of the cost of remediating another former MGP site in Grand Forks, N.D. The $2.9-million recovered cost of remediating that site was accumulated in a regulatory asset that is now being expensed evenly over eight years. NSP-Minnesota may request recovery of costs to remediate other sites following the completion of preliminary investigations.

NRG Site Remediation As part of acquiring existing generating assets, NRG has acquired certain environmental liabilities associated with regulatory compliance and site contamination. Often, potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in governmental priorities or (e) selection of a less expensive compliance option than originally envisioned.

In response to liabilities associated with these activities, NRG has established accruals where reasonable estimates of probable liabilities are possible. As of Dec. 31, 2002 and 2001, NRG has established such accruals in the amount of approximately $3.8 million and $5.0 million, respectively, primarily related to its Northeast region facilities. NRG has not used discounting in determining its accrued liabilities for environmental remediation and no claims for possible recovery from third party issuers or other parties related to environmental costs have been recognized in NRG's consolidated financial statements. NRG adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information. During the years ended Dec. 31, 2002, 2001 and 2000, NRG recorded expenses of approximately $10.9 million, $15.3 million and $3.4 million related to environmental matters, respectively.

Asbestos Removal 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.

Leyden Gas Storage Facility In February 2001, the CPUC granted PSCo's application to abandon the Leyden natural gas storage facility (Leyden) after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. Since late 2001, PSCo has operated the facility to withdraw the recoverable gas in inventory. Beginning in 2003, PSCo will start to flood the facility with water, as part of an overall plan to convert Leyden into a municipal water storage facility owned and operated by the city of Arvada, Colo. As of Dec. 31, 2002, PSCo has deferred approximately $4.5 million of costs associated with engineering buffer studies, damage claims paid to landowners and other closure costs. PSCo expects to incur an additional $6 million to $8 million of costs through 2005 to complete the decommissioning and closure of the facility. PSCo believes that these costs will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

PSCo Notice of Violation On Nov. 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act's New Source Review (NSR) requirements related to alleged modifications of electric generating stations located in the South and Midwest. Subsequently, the U. S. Environmental Protection Agency (EPA) also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to EPA's initial information requests related to PSCo plants in Colorado.

On July 1, 2002, Xcel Energy received a Notice of Violation (NOV) from the EPA alleging violations of the NSR requirements of the Clean Air Act at the Comanche and Pawnee stations in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. Xcel Energy believes it acted in full compliance with the Clean Air Act and NSR process. It believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. Xcel Energy also believes that the projects would be expressly authorized under the EPA's NSR policy announced by the EPA administrator on June 22, 2002, and proposed in the Federal Register on Dec. 31, 2002. Xcel Energy disagrees with the assertions contained in the NOV and intends to vigorously defend its position. As required by the Clean Air Act, the EPA met with Xcel Energy in September 2002 to discuss the NOV.

If the EPA is successful in any subsequent litigation regarding the issues set forth in the NOV or any matter arising as a result of its information requests, it could require Xcel Energy to install additional emission-control equipment at the facilities and pay civil penalties. Civil penalties are limited to not more than $25,000 to $27,500 per day for each violation, commencing from the date the violation began. The ultimate financial impact to Xcel Energy is not determinable at this time.

NSP-Minnesota NSR Information Request As stated previously, on Nov. 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act's NSR requirements related to alleged modifications of electric generating stations located in the South and Midwest. Subsequently, the EPA also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to the EPA's initial information requests related to NSP-Minnesota plants in Minnesota. On May 22, 2002, the EPA issued a follow-up information request to Xcel Energy seeking additional information regarding NSR compliance at its plants in Minnesota. Xcel Energy completed its response to the follow-up information request during the fall of 2002.

NSP-Minnesota Notice of Violation On Dec. 10, 2001, the Minnesota Pollution Control Agency issued a notice of violation to NSP-Minnesota alleging air quality violations related to the replacement of a coal conveyor and violations of an opacity limitation at the A.S. King generating plant. NSP-Minnesota has responded to the notice of violation and is working to resolve the allegations.

Nuclear Insurance NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $9.4 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 $9.2 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 the 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 $7.5 million for business interruption insurance and $21.6 million for property damage insurance if losses exceed accumulated reserve funds.

Louisiana Generating – Pointe Coupee On Dec. 2, 2002, a petition was filed to appeal the EPA's approval of the Louisiana Department of Environmental Quality's (LDEQ) revisions to the state implementation plan (SIP) regarding emissions regulations. Pointe Coupee and NRG's subsidiary, Louisiana Generating, object to the permitting requirements regarding nitrogen oxide (NO_x) sources requiring the LDEQ to obtain offsets of major increases in emissions of NO_x associated with major modifications of existing facilities or construction of new facilities areas, including Pointe Coupee Parish. The plaintiffs' challenge is based on LDEQ's failure to comply with requirements related to rulemaking and the EPA's regulations, which prohibit EPA from approving a SIP not prepared in accordance with state law. The court granted a 60-day stay of this proceeding on Feb. 25, 2003, to allow the parties to conduct settlement discussions. At this time, NRG is unable to predict the eventual outcome of this matter or any potential loss contingencies.

Louisiana Generating – New Construction Air Permits During 2000, the LDEQ issued an air permit modification to Louisiana Generating to construct and operate two 240-megawatt, natural gas-fired turbines. The permit set emissions limits for certain air pollutants, including NO_x. The limitation for NO_x was based on the guarantees of the manufacturer, Siemens Westinghouse Power Corporation (Siemens). Louisiana Generating sought an interim emissions limit to allow Siemens time to install additional control equipment. To establish the interim limit, LDEQ issued an order and Notice of Potential Penalty in September 2002, which is, in part, subject to a hearing. LDEQ alleged that Louisiana Generating did not meet its NO_x emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO_x. An initial status conference has been held with the administrative law judge, and quarterly reports will be submitted to describe progress, including settlement and amendment of the limit. In addition, NRG may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time NRG is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which NRG may be subject.

LEGAL CONTINGENCIES

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.

The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy's financial position and results of operations.

St. Cloud Gas Explosion 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 24 lawsuits relating to the explosion. NSP-Minnesota, Seren's parent company at the time, is a defendant in 21 of the lawsuits. In addition to compensatory damages, plaintiffs are seeking punitive damages against CCI and Seren. 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 causes 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.

California Litigation NRG and other power generators and power traders have been named as defendants in a multi-district litigation proceeding. These cases were all filed in late 2000 and 2001 in various state courts throughout California. They allege unfair competition, market manipulation and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the multi-district litigation panel. The cases were ultimately assigned to Judge Whaley. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanded the cases to state court. On Feb. 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear an appeal of the remand order. NRG anticipates that filed-rate/federal preemption pleading challenges will once again be filed once the remand appeal is decided. A notice of bankruptcy filing regarding NRG has also been filed in this action, providing notice of the involuntary petition.

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 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. These six civil actions brought against NRG and other power generators and power traders in California have been consolidated in the San Diego County Superior Court, and the plaintiffs in these six consolidated civil actions filed a master amended complaint reiterating the allegations contained in their complaints and alleging that the defendants' anti-competitive conduct damaged the general public and class members in an amount in excess of $1.0 billion. Two of the defendants in these actions, Reliant and Duke, subsequently filed cross-complaints naming additional market participants, some of whom removed the actions to the United States District Court for the Southern District of California federal court. Now under advisement in that court is the plaintiffs' motion to remand the cases to state court and motions by the cross-defendants to dismiss the cases against them.

In addition, Public Utility District No. 1 of Snohomish County, Washington, has filed a suit against NRG, Xcel Energy and several other market participants in United States District Court for the Central District of California contending that some of its trading strategies, as reported to the FERC in response to that agency's investigation of trading strategies discussed above, violated the California Business and Professions Code. Public Utility District No. 1 of Snohomish County contends that the effect of those strategies was to increase amounts that it paid for wholesale power in the spot market in the Pacific Northwest. Judge Whaley granted a motion to dismiss on the grounds of federal preemption and filed-rate doctrine, which the plaintiffs have appealed.

Separate class action lawsuits alleging unfair competition similar to those filed in California, as discussed previously, have been filed in Oregon and Washington. These lawsuits have named both Xcel Energy and NRG as respondents.

California Attorney General In addition to the litigation described above, the California Attorney General has undertaken an investigation into actions affecting electricity prices in California. In connection with this investigation, the Attorney General has issued subpoenas and requested other information from Dynegy and NRG. NRG responded to the interrogatories as requested. Management cannot make any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions at this time. NRG knows of no evidence implicating NRG in plaintiffs' allegations of collusion.

FirstEnergy Arbitration Claim In August 2002, FirstEnergy terminated the purchase agreements pursuant to which NRG had agreed to purchase four generating stations for approximately $1.5 billion. FirstEnergy's cited rationale for terminating the agreements was an alleged anticipatory breach by NRG. FirstEnergy notified NRG that it is reserving the right to pursue legal action against NRG and Xcel Energy for damages. On Feb. 21, 2003, FirstEnergy submitted filings with the United States Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On Feb. 26, 2002, FirstEnergy commenced the arbitration proceedings against NRG, but have yet to quantify their damage claim. NRG cannot presently predict the outcome of this dispute.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes NRG and/or its affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company (GE) and Siemens. GE and Siemens have notified NRG that it is in default under certain of those contracts, terminated such contracts and demanded that NRG pay the termination fees set forth in such contracts. GE's claim amounts to $120 million and Siemens' approximately $45 million in cumulative termination charges. NRG has recorded a liability for the amounts they believe they owe under the contracts and termination provisions. NRG cannot estimate the likelihood of unfavorable outcomes in these disputes.

Fortistar Litigation On Feb. 26, 2003, Fortistar Capital, Inc. and Fortistar Methane, LLC filed a $1-billion lawsuit in the Federal District Court for the Northern District of New York against Xcel Energy Inc. and five former NRG or NEO Corp. employees. In the lawsuit, Fortistar claims that the defendants violated the Racketeer Influenced and Corrupt Organizations Act (RICO) and committed fraud by engaging in a pattern of negotiating and executing agreements "they intended not to comply with" and "made false statements later to conceal their fraudulent promises." The allegations against Xcel Energy are, for the most part, limited to purported activities related to the contract for the Pike Energy power facility in Mississippi and statements related to an "equity infusion" into NRG by Xcel Energy. The plaintiffs allege damages of some $350 million and also assert entitlement to a trebling of these damages under the provisions of the RICO. The present and former NRG and NEO officers and employees have requested indemnity from NRG, which requests NRG is now examining. Xcel Energy cannot at this time estimate the likelihood of an unfavorable outcome to the defendants in this lawsuit.

Itiquira Energetica NRG's indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156-megawatt hydro project in Brazil, is currently in arbitration with a former contractor for the project Inepar Industria e Construcoes (Inepar). The dispute was commenced by Itiquira in September 2002 and pertains to certain matters arising under the agreement with the contractor. Itiquira principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira's arbitration claim is for approximately $40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar's damage claim is for approximately $10 million. On Nov. 12, 2002, Inepar submitted its affirmative statement of claim, and Itiquira submitted its response and statement of counterclaims on Dec. 14, 2002. Inepar replied to Itiquira's response and counterclaims on Jan. 14, 2003. Itiquira was to submit its reply on March 14, 2003, and a hearing was held on March 21, 2003. NRG cannot estimate the likelihood of an unfavorable outcome in this dispute.

NRG Bankruptcy On Oct. 17, 2002, a petition commencing an involuntary bankruptcy proceeding pursuant to Chapter 7 of the Bankruptcy Code was filed against LSP-Pike Energy, LLC, a subsidiary of NRG, by Stone & Webster, Inc. and Shaw Constructors, Inc., the joining petitioners in the Minnesota involuntary case described previously, in the United States Bankruptcy Court for the Southern District of Mississippi. In their petition, the joining petitioners sought recovery of allegedly unpaid contractual construction-related obligations in an aggregate amount of $74 million, which amount LSP-Pike Energy, LLC has disputed. LSP-Pike Energy, LLC filed an answer to the petition in the Mississippi involuntary case and served various interrogatory and deposition discovery requests on the joining petitioners. The Mississippi Bankruptcy Court has not entered any order for relief in the Mississippi involuntary case.

On Nov. 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota Bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners' claims and filing a motion to dismiss the case. A hearing was set for April 10, 2003, to consider the motion to dismiss. In their petition, the petitioners sought recovery of severance and other benefits of approximately $28 million.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On Feb. 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million. The Minnesota Bankruptcy Court has discretion in reviewing and ruling on the motion to dismiss and the review and approval of the Settlement Agreement. There is a risk that the Minnesota Bankruptcy Court may, among other things, reject the Settlement Agreement or enter an order for relief under Chapter 11 of Title 11 of the Bankruptcy Code.

See Note 4 for additional discussion of possible NRG bankruptcy.

NRG Energy, Inc. Shareholder Litigation (Delaware); Rosenfeld v. NRG Energy, Inc. (Minnesota) In February 2002, individual stockholders of NRG filed nine separate, but similar, purported class action complaints in the Delaware Court of Chancery, subsequently consolidated and with a single amended complaint, against Xcel Energy, NRG and the nine members of NRG's board of directors. In March 2002, a similar class action lawsuit was filed in the state trial court for Hennepin County, Minnesota. Each of the actions challenged the proposed purchase by Xcel Energy, via exchange offer and follow-up merger, of the approximately 26 percent of the outstanding shares of NRG that it did not already own; contained various allegations of wrongdoing on the part of the defendants in connection with the proposed purchase, including violations of fiduciary duties of loyalty and candor; and sought injunctive and damage relief and an award of fees and expenses. In April 2002, counsel for the parties to the consolidated action in the Delaware Court of Chancery and the Minnesota action entered into a memorandum of understanding setting forth an agreement in principle to settle the actions based on the increase by Xcel Energy of the exchange ratio in the offer and merger to 0.5000 but subject to confirmatory discovery, definitive documentation and court approval. The Minnesota action has subsequently been dismissed without prejudice. As to the Delaware actions, the settlement has not been documented, approved or consummated, and, in light of developments in the litigation that is described under the heading immediately below, it is uncertain whether the settlement will proceed.

Xcel Energy Inc. Securities Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy's common stock between Jan. 31, 2001, and July 26, 2002, was filed in the United States District Court for the District of Minnesota. The complaint named Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Edward J. McIntyre, former vice president and chief financial officer; and former chairman James J. Howard as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act and Rule 10(b-5) related to allegedly false and misleading disclosures concerning various issues, including but not limited to "round trip" energy trades, the nature, extent and seriousness of liquidity and credit difficulties at NRG, and the existence of cross-default provisions (with NRG credit agreements) in certain of Xcel Energy's credit agreements.

After the filing of the lawsuit, several additional lawsuits were filed with similar allegations, one of which added claims on behalf of a purported class of purchasers of two series of Senior Notes issued by NRG in January 2001. The cases have all been consolidated, and a consolidated amended complaint has been filed. The amended complaint charges false and misleading disclosures concerning "round trip" energy trades and the existence of provisions in Xcel Energy's credit agreements for cross-defaults in the event of a default by NRG in one or more of NRG's credit agreements; it adds as additional defendants Gary R. Johnson, general counsel; Richard C. Kelly, president of Xcel Energy Enterprises; three former executive officers of NRG, David H. Peterson, Leonard A. Bluhm and William T. Pieper, and a former independent director of NRG, Luella G. Goldberg; and it adds claims of false and misleading disclosures, also regarding "round trip" trades and the cross-default provisions, as well the extent to which the "fortunes" of NRG were tied to Xcel Energy, especially in the event of a buyback of NRG's publicly owned shares, under Section 11 of the Securities Act with respect to issuance of the Senior Notes. The amended complaint seeks compensatory and rescissionary damages, interest and an award of fees and expenses. The defendants have not yet responded to the amended complaint. Discovery has not commenced.

Xcel Energy Inc. Shareholder Derivative Action; Essmacher v. Brunetti; McLain v. Brunetti On Aug. 15, 2002, a shareholder derivative action was filed in the United States District Court for the District of Minnesota, purportedly on behalf of Xcel Energy, against the directors and certain present and former officers, citing essentially the same circumstances as the securities class actions described immediately preceding and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with the securities class actions. After the filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota, against essentially the same defendants, focusing on allegedly wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish adequate accounting controls, abuse of control and gross mismanagement. Considered collectively, the complaints seek compensatory damages, a return of compensation received and awards of fees and expenses. In each of the cases, the defendants have filed motions to dismiss the complaint for failure to make a proper pre-suit demand, or in the federal court case, to make any pre-suit demand at all, upon Xcel Energy's board of directors. The motions have not yet been ruled upon. Discovery has not commenced.

Newcome v. Xcel Energy Inc.; Barday v. Xcel Energy Inc. On Sept. 23, 2002, and Oct. 9, 2002, two essentially identical actions were filed in the United States District Court for the District of Colorado, purportedly on behalf of classes of employee participants in Xcel Energy's and its predecessors' 401(k) or ESOP plans from as early as Sept. 23, 1999, forward. The complaints in the actions name as defendants Xcel Energy, its directors, certain former directors and certain of present and former officers. The complaints allege violations of the Employee Retirement Income Security Act in the form of breach of fiduciary duty in allowing or encouraging purchase, contribution and/or retention of Xcel Energy's common stock in the plans and making misleading statements and omissions in that regard. The complaints seek injunctive relief, restitution, disgorgement and other remedial relief, interest and an award of fees and expenses. The defendants have filed motions to dismiss the complaints upon which no rulings have yet been made. The plaintiffs have made certain voluntary disclosure of information, but otherwise discovery has not commenced. Upon motion of defendants, the cases have been transferred to the District of Minnesota for purposes of coordination with the securities class actions and shareholders derivative action pending there.

Stone & Webster, Inc. v. Xcel Energy Inc. On Oct. 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court in Mississippi against Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Richard C. Kelly, president of Xcel Energy Enterprises; NRG and certain NRG subsidiaries. Plaintiffs allege they had a contract with a single purpose NRG subsidiary for construction of a power generation facility, which was abandoned before completion but after substantial sums had been spent by plaintiffs. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy and aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The complaint seeks compensatory damages of at least $130 million plus demobilization and cancellation costs and punitive damages at least treble the compensatory damages. On Dec. 23, 2003, defendants filed motions to dismiss the complaint, which have not yet been ruled upon. No trial date has been set in this matter, and Xcel Energy cannot presently predict the outcome of this dispute. Plaintiffs have commenced what they characterize as jurisdictional discovery, which defendants are resisting.

New York Independent System Operator (NYISO) Claims In November 2002, the NYISO notified NRG of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. NRG contests both the validity and calculation of the claims and is currently negotiating with the NYISO over the ultimate disposition. Accordingly, NRG reduced its revenues by $21.7 million and recorded a corresponding reserve for the receivable.

Huntley and Dunkirk Litigation In January 2002, the New York Attorney General and the New York Department of Environmental Control (NYDEC) filed suit in federal district court in New York against NRG and Niagara Mohawk Power Corp. (NiMo), the prior owner of the Huntley and Dunkirk facilities in New York. The lawsuit relates to physical changes made at those facilities prior to NRG's assumption of ownership. The complaint alleges that these changes represent major modifications undertaken without the required permits having been obtained. Although NRG has a right to indemnification by the previous owner for fines, penalties, assessments and related losses resulting from the previous owner's failure to comply with environmental laws and regulations, NRG could be enjoined from operating the facilities if the facilities are found not to comply with applicable permit requirements. In addition, NRG could be required to bear the costs of installing emissions controls. On March 27, 2003, the court dismissed the complaint against NRG without prejudice. If the case is litigated to a judgment and there is an unfavorable outcome, NRG has estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a 10- to 12-year period. NRG has asserted that NiMo is obligated to indemnify it for any related compliance costs associated with resolution of the NYDEC enforcement action.

In July 2001, Niagara Mohawk Power Corp. filed a declaratory judgment action in the Supreme Court for the State of New York, County of Onondaga, against NRG and its wholly owned subsidiaries Huntley Power LLC and Dunkirk Power LLC. Niagara Mohawk Power Corp. requests a declaration by the court that, pursuant to the terms of the asset sales agreement (ASA) under which NRG purchased the Huntley and Dunkirk generating facilities from Niagara Mohawk, defendants have assumed liability for any costs for the installation of emissions controls or other modifications to or related to the Huntley or Dunkirk plants imposed as a result of violations or alleged violations of environmental law. Niagara Mohawk Power Corporation also requests a declaration by the court that, pursuant to the ASA, defendants have assumed all liabilities, including liabilities for natural resource damages, arising from emissions or releases of pollutants from the Huntley and Dunkirk plants, without regard to whether such emissions or releases occurred before, on or after the closing date for the purchase of the Huntley and Dunkirk plants. NRG has counterclaimed against Niagara Mohawk Power Corp., and the parties have exchanged discovery requests.

On Oct. 2, 2000, plaintiff NiMo commenced an action against NRG to recover net damages through the date of judgment, as well as any additional amounts due and owing for electric service provided to the Dunkirk plant after Sept. 18, 2000. NiMo claims that NRG has failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999, and continuing to Sept. 18, 2000, and thereafter. On Aug. 9, 2002, the parties filed a stipulation consolidating this action with two other actions against the Huntley and Oswego subsidiaries of NRG. On Oct. 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action pending submission of some or all of the disputes in the action to the FERC. NRG cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

OTHER CONTINGENCIES

Operating Contingency As discussed in Note 19, NSP-Minnesota is experiencing uncertainty regarding its ability to store used nuclear fuel from its Prairie Island and Monticello nuclear generating facilities. These facilities store used nuclear fuel in a storage pool or dry cask storage on the plant site, pending the availability of a DOE high-level radioactive substance storage or permanent disposal facility, or a private interim storage facility.

The Prairie Island plant is licensed by the federal Nuclear Regulatory Commission (NRC) to store up to 48 casks of spent fuel at the plant. In 1994, the Minnesota Legislature adopted a limit on dry cask storage of 17 casks for the entire state. The 17 casks, which stand outside the Prairie Island plant, are now full, and under the current configuration, the storage pool within the plant would be full by 2007. Prairie Island cannot operate beyond 2007 unless the existing spent fuel is moved or the storage capacity is increased. Because the 17-cask limit is a statewide limit, the Monticello plant cannot, under current state law, store spent fuel in dry casks. Monticello's on-site storage pool is expected to be full in 2010. Monticello cannot operate beyond 2010 unless the existing spent fuel is moved or the storage capacity is increased. Capitalized costs for Prairie Island and Monticello are being depreciated over these available storage periods, and no unamortized plant investment is expected to remain if the plants must shut down in 2007 and 2010, respectively.

Due to the investment decisions required to be made in conjunction with the continued efficient operation of the nuclear plants, as well as the time and cost involved to develop alternatives to the existing nuclear power generation, NSP-Minnesota believes a decision is necessary in 2003 by the Minnesota Legislature whether the state will allow the continued use of nuclear power in the future. Prairie Island will only be able to continue operating beyond 2007 with legislative authorization of additional storage space. If additional storage space for continued operations is not authorized, and interim storage is not available, legislation may be required to ensure expedited siting and permitting of new generation or transmission facilities in time to replace the power supply currently provided from NSP-Minnesota's nuclear plants.

NSP-Minnesota has developed replacement power options, including purchasing new coal or natural gas generation sources. The feasibility of supplementing new generation sources with additional wind turbines has been reviewed. These options have been presented to the 2003 Minnesota Legislature. Each option involves a balance of cost, environmental impacts and production efficiencies. Based on the review of these options, NSP-Minnesota believes the most reliable, lowest-cost, emissions-free method to provide the needed 1,700 megawatts of energy is to continue to operate the nuclear power plants at Prairie Island and Monticello, which is possible only with the additional approved storage capacity for spent fuel, either on-site or in a private facility. We cannot predict at this time what resource decisions the Minnesota Legislature or MPUC may make regarding the continued use of NSP-Minnesota's Prairie Island and Monticello nuclear plants. If decisions are not made that allow the plants' use beyond the storage capacity period, additional costs may need to be incurred to provide replacement power, either from new generating plants or from purchased power. The amount of such additional costs, and the level of corresponding rate recovery provided, are not determinable at this time but may be material.

Tax Matters PSCo's wholly owned subsidiary PSR Investments, Inc. (PSRI) owns and manages permanent life insurance policies on PSCo employees, known as corporate-owned life insurance (COLI). At various times, we have made borrowings against the cash values of these COLI policies and deducted the interest expense on these borrowings. The IRS had issued a Notice of Proposed Adjustment proposing to disallow interest expense deductions taken in tax years 1993 through 1997 related to COLI policy loans. A request for technical advice from the IRS National Office with respect to the proposed adjustment had been pending. Late in 2001, Xcel Energy received a technical advice memorandum from the IRS National Office, which communicated a position adverse to PSRI. Consequently, we expect the IRS examination division to begin the process of disallowing the interest expense deductions for the tax years 1993 through 1997.

After consultation with tax counsel, it is Xcel Energy's position that the IRS determination is not supported by the tax law. Based upon this assessment, management continues to believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the tax law. Therefore, Xcel Energy intends to challenge the IRS determination, which could require several years to reach final resolution. Although the ultimate resolution of this matter is uncertain, management continues to believe 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. However, defense of Xcel Energy's position may require significant cash outlays on a temporary basis, if refund litigation is pursued in United States District Court.

The total disallowance of interest expense deductions for the period of 1993 through 1997, as proposed by the IRS, is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2002, would reduce earnings by an estimated $214 million after tax.

Seren At Dec. 31, 2002, Xcel Energy's investment in Seren was approximately $255 million. Seren had capitalized $290 million for plant in service and had incurred another $21 million for construction work in progress for these systems. The construction of its broadband communications network in Minnesota and California has resulted in consistent losses. Management currently intends to hold and operate Seren, and believes that no asset impairment exists. Xcel Energy projects improvements in Seren's operating results, with positive cash flows in 2005 and an earnings contribution anticipated in 2008.

Xcel Energy International At Dec. 31, 2002, Xcel Energy's investment in Argentina, through Xcel Energy International, was approximately $112 million. In December 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide full recovery of Xcel International's investment. An impairment write-down of approximately $13 million was recorded in the fourth quarter of 2002.

19. 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-Minnesota'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 $13 million in 2002, $11 million in 2001 and $12 million in 2000. In total, NSP-Minnesota had paid approximately $312 million to the DOE through Dec. 31, 2002. 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 for spent fuel 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 all of the 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 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2002 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 $21 million at Dec. 31, 2002, as a regulatory asset.

Plant Decommissioning Decommissioning of NSP-Minnesota's nuclear facilities is planned for the years 2010 through 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 Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy's Consolidated Financial Statements.

Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are licensed to operate until 2013 and 2014, respectively. Once a decision is made by the Minnesota Legislature regarding interim spent fuel storage facilities, Xcel Energy will make a decision on whether to pursue license renewal for Monticello and Prairie Island plants. Applications for license renewal must be submitted to the Nuclear Regulatory Commission (NRC) at least five years prior to license expiration. Preliminary scoping efforts for license renewal of the Monticello plant have begun, including data collection and review. The Prairie Island license renewal process has not yet begun. Xcel Energy's decision whether to apply for license renewal approval could be contingent on incremental plant maintenance or capital expenditures, recovery of which would be expected from customers through the respective rate recovery mechanisms. Management cannot predict the specific impact of such future requirements, if any, on its results of operations.

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 "Accounting for Asset Retirement Obligations." This statement will require NSP-Minnesota to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset's useful life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 are met. NSP-Minnesota adopted SFAS No. 143 as required on Jan. 1, 2003. For additional information, see Note 20 to the Consolidated Financial Statements.

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 4.35 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. Unrealized gains on nuclear decommissioning investments are deferred as Regulatory Liabilities based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in April 2000, using 1999 cost data. A new filing was submitted to the MPUC in October 2002 that requests continuation of the current accrual. Since the timeframe is getting short on the recovery of the Prairie Island costs, less than five years at the start of 2003, NSP-Minnesota has recommended that the next filing be submitted in October 2003. The Department of Commerce has recommended that the internal fund, which is currently being transferred to the external funds, be transferred over a shorter period of time. This proposal would increase the fund cash contribution by approximately $13 million in 2003, but may not have a statement of operations impact. 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 spent-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, 2002, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in one to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

At Dec. 31, 2002, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $662 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation at Dec. 31, 2002:

(Thousands of dollars)	*2002*
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	**$ 958,266**
Effect of escalating costs to 2002 dollars (at 4.35 percent per year)	**130,573**
Estimated decommissioning cost obligation in current dollars	**1,088,839**
Effect of escalating costs to payment date (at 4.35 percent per year)	**805,435**
Estimated future decommissioning costs (undiscounted)	**1,894,274**
Effect of discounting obligation (using risk-free interest rate)	**(828,087)**
Discounted decommissioning cost obligation	**1,066,187**
Assets held in external decommissioning trust	**617,048**
Discounted decommissioning obligation in excess of assets currently held in external trust	**$ 449,139**

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	***2002***	*2001*	*2000*
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	**$51,433**	$51,433	$51,433
Internally funded (including interest costs)	**(18,797)**	(17,396)	(16,111)
Interest cost on externally funded decommissioning obligation	**(32)**	4,535	5,151
Earnings from external trust funds	**32**	(4,535)	(5,151)
Net decommissioning accruals recorded	**$32,636**	$34,037	$35,322

Decommissioning and interest accruals are included with Accumulated Depreciation on the Consolidated Balance Sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the statement of operations.

Negative accruals for internally funded portions in 2000, 2001 and 2002 reflect the impacts of the 1999 decommissioning study, which has approved an assumption of 100-percent external funding of future costs. Previous studies assumed a portion was funded internally; beginning in 2000, accruals are reversing the previously accrued internal portion and increasing the external portion prospectively.

20. REGULATORY ASSETS AND LIABILITIES

Our regulated businesses prepare their Consolidated Financial Statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Consolidated Financial Statements. Under SFAS No. 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. Any portion of our business that is not regulated cannot use SFAS No. 71 accounting. The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

(Thousands of dollars)	*Note Reference*	*Remaining Amortization Period*	*2002*	*2001*
AFDC recorded in plant *(a)*		Plant lives	**$154,158**	$149,591
Conservation programs *(a) (e)*		Up to five years	**53,860**	65,825
Losses on reacquired debt	1	Term of related debt	**85,888**	95,394
Environmental costs	18, 19	To be determined	**30,974**	20,169
Unrecovered electric production costs *(d)*	1	27 months	**67,709**	–
Unrecovered natural gas costs *(b)*	1	One to two years	**11,950**	11,316
Deferred income tax adjustments	1	Mainly plant lives	**18,611**	17,799
Nuclear decommissioning costs *(c)*		Up to eight years	**53,567**	68,484
Employees' postretirement benefits other than pension	13	10 years	**38,899**	42,942
Employees' postemployment benefits	2	One year	**–**	119
Renewable resource costs		To be determined	**26,000**	17,500
State commission accounting adjustments *(a)*		Plant lives	**19,157**	7,578
Other		Various	**15,630**	5,725
Total regulatory assets			**$576,403**	$502,442
Investment tax credit deferrals			**$109,571**	$117,257
Unrealized gains from decommissioning investments	19		**112,145**	149,041
Pension costs-regulatory differences	13		**287,615**	215,687
Interest on income tax refunds			**6,569**	–
Fuel costs, refunds and other			**2,527**	1,957
Total regulatory liabilities			**$518,427**	$483,942

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(b) Excludes current portion with expected rate recovery within 12 months of $12 million and $22 million for 2002 and 2001, respectively.
(c) These costs do not relate to NSP-Minnesota's nuclear plants. They relate to DOE assessments, as discussed previously, and unamortized costs for PSCo's Fort St. Vrain nuclear plant decommissioning.
(d) Excludes current portion with expected rate recovery within 12 months of $54 million and $0 million for 2002 and 2001, respectively.
(e) 2001 amount includes accrued conservation incentives expected to be approved for 2001.

This table excludes deferred energy charges expected to be recovered within the next 12 months of $28 million for 2002, and energy cost recovery expected to be returned to customers within the next 12 months of $26 million for 2001.

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 – "Accounting for Asset Retirement Obligations." This statement will require Xcel Energy to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset's life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires that a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation" are met.

Xcel Energy currently follows industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in accumulated depreciation. At Dec. 31, 2002, Xcel Energy recorded and recovered in rates $662 million of decommissioning obligations and had estimated discounted decommissioning cost obligations of $1.1 billion based on approvals from the various state commissions, which used a single scenario. However, with the adoption of SFAS No. 143, a probabilistic view of several decommissioning scenarios was used, resulting in an estimated discounted decommissioning cost obligation of $1.6 billion.

Xcel Energy expects to adopt SFAS No. 143 as required on Jan. 1, 2003. In current estimates for adoption, the initial value of the liability, including cumulative accretion expense through that date, would be approximately $869 million. This liability would be established by reclassifying accumulated depreciation of $573 million and by recording two long-term assets totaling $296 million. A gross capitalized asset of $130 million would be recorded and would be offset by accumulated depreciation of $89 million. In addition, a regulatory asset of approximately $166 million would be recorded for the cumulative effect adjustment related to unrecognized depreciation and accretion under the new standard. Management expects that the entire transition amount would be recoverable in rates over time and, therefore, would support this regulatory asset upon adoption of SFAS No. 143.

Xcel Energy has completed a detailed assessment of the specific applicability and implications of SFAS No. 143 for obligations other than nuclear decommissioning. Other assets that may have potential asset retirement obligations include ash ponds, any generating plant with a Part 30 license and electric and natural gas transmission and distribution assets on property under easement agreements. Easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The liability is not estimable because Xcel Energy intends to utilize these properties indefinitely. The asset retirement obligations for the ash ponds and generating plants cannot be reasonably estimated due to an indeterminate life for the assets associated with the ponds and uncertain retirement dates for the generating plants. Since the time period for retirement is unknown, no liability would be recorded. When a retirement date is certain, a liability will be recorded.

The adoption of SFAS No. 143 in 2003 will also affect Xcel Energy's accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a generally accepted accounting principles liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, the estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 143 that are accrued in accumulated depreciation, are as follows at Dec. 31:

(Millions of dollars)	*2002*
NSP-Minnesota	**$304**
NSP-Wisconsin	**$ 70**
PSCo	**$329**
SPS	**$ 97**

21. SEGMENTS AND RELATED INFORMATION

Xcel Energy has the following reportable segments: Electric Utility, Natural Gas Utility and its nonregulated energy business, NRG. Previously, e prime was considered a reportable segment due to the significance of its gross trading revenues. However, with the change in reporting of trading operations to a net basis, as discussed in Note 1 to the Consolidated Financial Statements, e prime is no longer a reportable segment due to its net trading margins/revenue being below the quantitative thresholds. e prime is included in the All Other category for all periods presented.

- 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 Natural 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, 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.

Revenues from operating segments not included previously are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include a company that trades and markets natural gas throughout the United States; 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 to the Consolidated Financial Statements. 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*	*Natural Gas Utility*	*NRG (b)*	*All Other (b)*	*Reconciling Eliminations*	*Consolidated Total*
2002						
Operating revenues from external customers *(a)*	**$5,437,017**	**$1,397,799**	**$ 2,212,153**	**$405,839**	**$ –**	**$ 9,452,808**
Intersegment revenues	**987**	**4,949**	**–**	**165,732**	**(171,665)**	**3**
Equity in earnings (losses) of unconsolidated affiliates *(a)*	**–**	**–**	**68,996**	**2,565**	**–**	**71,561**
Total revenues	**$5,438,004**	**$1,402,748**	**$ 2,281,149**	**$574,136**	**$(171,665)**	**$ 9,524,372**
Depreciation and amortization	**$ 647,491**	**$ 92,868**	**$ 256,199**	**$ 40,871**	**$ –**	**$ 1,037,429**
Financing costs, mainly interest expense	**286,180**	**52,583**	**493,956**	**131,383**	**(46,022)**	**918,080**
Income tax expense (credit)	**301,875**	**53,831**	**(165,382)**	**(818,309)**	**–**	**(627,985)**
Segment net income (loss)	**$ 478,711**	**$ 98,517**	**$(3,464,282)**	**$715,140**	**$ (46,077)**	**$(2,217,991)**
2001						
Operating revenues from external customers *(a)*	$6,463,401	$2,051,199	$ 2,201,427	$397,895	$ –	$11,113,922
Intersegment revenues	978	4,501	1,859	178,111	(183,019)	2,430
Equity in earnings (losses) of unconsolidated affiliates *(a)*	–	–	210,032	7,038	–	217,070
Total revenues	$6,464,379	$2,055,700	$ 2,413,318	$583,044	$(183,019)	$11,333,422
Depreciation and amortization	$ 617,320	$ 92,989	$ 169,596	$ 26,398	$ –	$ 906,303
Financing costs, mainly interest expense	265,285	49,108	389,311	115,127	(52,055)	766,776
Income tax expense (credit)	351,181	41,077	28,052	(88,939)	–	331,371
Segment income (loss) before extraordinary items	$ 535,182	$ 81,562	$ 265,204	$ (56,879)	$ (40,390)	$ 784,679
Extraordinary items, net of tax	11,821	–	–	(1,534)	–	10,287
Segment net income (loss)	$ 547,003	$ 81,562	$ 265,204	$ (58,413)	$ (40,390)	$ 794,966
2000						
Operating revenues from external customers *(a)*	$5,704,683	$1,466,478	$ 1,670,774	$195,236	$ –	$ 9,037,171
Intersegment revenues	1,179	5,761	2,256	132,347	(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates *(a)*	–	–	139,364	43,350	–	182,714
Total revenues	$5,705,862	$1,472,239	$ 1,812,394	$370,933	$(137,962)	$ 9,223,466
Depreciation and amortization	$ 574,018	$ 85,353	$ 97,304	$ 10,071	$ –	$ 766,746
Financing costs, mainly interest expense	333,512	60,755	250,790	67,696	(59,780)	652,973
Income tax expense (credit)	261,942	36,962	86,903	(86,777)	–	299,030
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)	–	–	–	–	(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 526,828

(a)

(Millions of dollars)	*2002 NRG*	*2002 All Other*	*2001 NRG*	*2001 All Other*	*2000 NRG*	*2000 All Other*
Operating revenues from external customers – United States	***$1,874***	***$369***	*$1,886*	*$362*	*$1,575*	*$195*
Operating revenues from external customers – international	***338***	***37***	*315*	*36*	*96*	*–*
Equity in earnings of unconsolidated affiliates – United States	***20***	***3***	*151*	*6*	*121*	*8*
Equity in earnings of unconsolidated affiliates – international	***49***	***–***	*59*	*1*	*18*	*35*
Consolidated earnings (loss) – international	***(695)***	***18***	*100*	*6*	*39*	*29*

NRG's international assets were $2,368 million and $3,199 million in 2002 and 2001, respectively. NRG's equity investments and projects outside the United States were $310 million and $417 million in 2002 and 2001, respectively.

All Other's international assets were $69 million and $138 million in 2002 and 2001, respectively. All Other's investments and projects outside the United States were $0 and $37 million in 2002 and 2001, respectively.

(b) NRG segment represents the consolidated results of NRG excluding the earnings attributable to minority shareholders of NRG prior to June 2002, when Xcel Energy acquired a 100-percent ownership in NRG. All Other includes minority interest income (expense) related to NRG of $13.6 million in 2002, $(65.6) million in 2001, and $(29.2) million in 2000. Also, in 2002, All Other includes income tax benefits related to Xcel Energy's investment in NRG of $706 million, as discussed in Note 11 to the Consolidated Financial Statements.

22. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

Subsequent to the issuance of Xcel Energy's financial statements for the quarter ended Sept. 30, 2002, NRG's management determined that the accounting for certain transactions required revision.

NRG determined that it had misapplied the provisions of SFAS No. 144 related to asset grouping in connection with the review for impairment of its long-lived assets during the quarter ended Sept. 30, 2002. SFAS No. 144 requires that for purposes of testing recoverability, assets be grouped at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. NRG recalculated the asset impairment tests in accordance with SFAS No. 144 using the appropriate asset grouping for independent cash flows for each generation facility. As a result, NRG concluded that asset impairments should have been recorded for two projects known as Bayou Cove Peaking Power LLC and Somerset Power LLC. Since NRG concluded that the "triggering events" that led to the impairment charge were experienced in the third quarter of 2002, the asset impairments related to these projects should have been recorded as of Sept. 30, 2002. NRG calculated the asset impairment charges for Bayou Cove Peaking Power LLC and Somerset Power LLC to be $126.5 million and $49.3 million, respectively.

In connection with NRG's year-end audit, two additional items were found to be inappropriately recorded as of Sept. 30, 2002. These items included the inappropriate treatment of interest rate swap transactions as cash flow hedges and the decrease in the value of a bond remarketing option from the original price paid by NRG. The error correction for the interest rate swaps resulted in the recording of additional income of $61.6 million as of Sept. 30, 2002. The recognition of the decrease in the value of the remarketing option resulted in a charge to income of $15.9 million as of Sept. 30, 2002.

A summary of the significant effects of the restatement, including the impact of fourth quarter discontinued operations decisions, on Xcel Energy's consolidated statements of operations for the three and nine months ended Sept. 30, 2002, is as follows:

	As Previously Reported		*As Restated*	
(Thousands of dollars, except per share amounts)	*Three Months Ended*	*Nine Months Ended*	*Three Months Ended*	*Nine Months Ended*
Consolidated Statements of Operations				
Revenue	$ 2,473,331	$ 7,070,824	$ 2,473,331	$ 7,070,824
Operating income	(1,948,725)	(1,334,201)	(2,140,418)	(1,525,894)
Income (loss) from continuing operations	(1,496,959)	(1,317,413)	(1,627,039)	(1,447,493)
Discontinued operations – income (loss)	(577,001)	(565,741)	(577,001)	(565,741)
Net income (loss)	(2,073,960)	(1,883,154)	(2,204,040)	(2,013,234)
Earnings (loss) available for common shareholders	(2,075,020)	(1,886,334)	(2,205,100)	(2,016,414)
Earnings (loss) per share from continuing operations – basic and diluted	$ (3.77)	$ (3.51)	$ (4.10)	$ (3.85)
Earnings (loss) per share discontinued operations – basic and diluted	$ (1.45)	$ (1.50)	$ (1.45)	$ (1.50)
Earnings per share – basic and diluted	$ (5.22)	$ (5.01)	$ (5.55)	$ (5.35)

During the fourth quarter of 2002, NRG determined that it had inadvertently offset its investment in Jackson County, Miss., bonds in the amount of $155.5 million against long-term debt of the same amount owed to the County. This resulted in an understatement of NRG's assets and liabilities by $155.5 million as of Sept. 30, 2002. In addition, the restatement for Bayou Cove Peaking LLC and Somerset Power LLC impairments reduced the previously reported net property, plant and equipment balance by $175.8 million. The restatement for the interest rate swaps had no impact on total shareholder's equity and the restatement for the remarketing option reduced other assets by $15.9 million.

Summarized quarterly unaudited financial data is as follows:

	Quarter Ended			
(Thousands of dollars, except per share amounts)	*March 31, 2002 (a)*	*June 30, 2002 (a)*	*Sept. 30, 2002 (a) (d) As Restated*	*Dec. 31, 2002 (a)*
Revenue *(c)*	$2,370,584	$2,226,909	$ 2,473,331	$2,453,548
Operating income (loss)	298,977	315,548	(2,140,418)	93,562
Income (loss) from continuing operations	93,929	85,617	(1,627,039)	(213,877)
Discontinued operations – income (loss)	9,575	1,685	(577,001)	9,120
Net income (loss)	103,504	87,302	(2,204,040)	(204,757)
Earnings (loss) available for common shareholders	102,444	86,242	(2,205,100)	(205,818)
Earnings (loss) per share from continuing operations – basic and diluted	$ 0.26	$ 0.22	$ (4.10)	$ (0.54)
Earnings (loss) per share discontinued operations – basic and diluted	$ 0.03	$ –	$ (1.45)	$ 0.02
Earnings (loss) per share total – basic and diluted	$ 0.29	$ 0.22	$ (5.55)	$ (0.52)

(Thousands of dollars, except per share amounts)	*Quarter Ended* *March 31, 2001*	*June 30, 2001 (b)*	*Sept. 30, 2001*	*Dec. 31, 2001 (b)*
Revenue *(c)*	$3,174,066	$2,743,822	$2,931,799	$2,483,735
Operating income	461,097	416,843	635,884	344,323
Income from continuing operations before extraordinary items	191,974	162,654	264,823	118,236
Discontinued operations – income (loss)	17,336	5,203	8,080	16,373
Extraordinary items – income	–	–	–	10,287
Net income	209,310	167,857	272,903	144,896
Earnings available for common shareholders	208,250	166,797	271,843	143,835
Earnings per share from continuing operations before extraordinary items – basic and diluted	$ 0.56	$ 0.47	$ 0.77	$ 0.34
Earnings per share discontinued operations – basic and diluted	$ 0.05	$ 0.02	$ 0.02	$ 0.05
Earnings per share extraordinary items – basic and diluted	$ –	$ –	$ –	$ 0.03
Earnings per share – basic and diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.42

(a) 2002 results include special charges and unusual items in all quarters, as discussed in Note 2 to the Consolidated Financial Statements.
- *First-quarter results were decreased by $9 million, or 1 cent per share, for a special charge related to utility/service company employee restaffing costs, and by $5 million, or 1 cent per share, for regulatory recovery adjustments at SPS.*
- *Second-quarter results were decreased by $36 million, or 9 cents per share, for NEO-related special charges taken by NRG.*
- *Third-quarter results (as restated) were decreased by $2.5 billion, or $5.97 per share, for special charges related to NRG asset impairments and financial restructuring, and were increased by $676 million, or $1.77 per share, due to estimated tax benefits related to Xcel Energy's investment in NRG.*
- *Fourth-quarter results were decreased by $100 million, or 24 cents per share, for special charges related to NRG asset impairments and financial restructuring costs, and increased by $30 million, or $0.08 per share, due to revisions to the estimated tax benefits related to Xcel Energy's investment in NRG.*

(b) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Note 2 to the Consolidated Financial Statements.
- *Second-quarter results were increased by $41 million, or 7 cents per share, for conservation incentive adjustments, and decreased by $23 million, or 4 cents per share, for a special charge related to postemployment benefits.*
- *Fourth-quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.*

(c) Certain items in the 2001 and 2002 quarterly income statements have been reclassified to conform to the 2002 annual presentation. These reclassifications included the netting of trading revenues and expenses previously reported gross, and NRG's discontinued operations, as discussed in Notes 1 and 3 to the Consolidated Financial Statements, respectively.

(d) Third-quarter 2002 results for NRG have been restated from amounts previously reported. NRG's asset impairments and restructuring charges for the quarter have been restated, increasing NRG's operating expenses by $192 million and a correction for interest rate swaps that resulted in additional income of $62 million, for a net effect of $130 million in additional loss for the quarter. As a result, Xcel Energy's Special Charges included in operating expenses for the quarter ended Sept. 30, 2002, increased by $192 million, or $0.50 per share.

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