BUSINESS SEGMENTS AND ORGANIZATIONAL OVERVIEW

Xcel Energy Inc. (Xcel Energy), a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). In 2003, Xcel Energy directly owned five utility subsidiaries that serve electric and natural gas customers in 11 states. These 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) and Cheyenne Light, Fuel and Power Co. (Cheyenne). These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Along with WestGas InterState Inc. (WGI), an interstate natural gas pipeline, these companies comprise our continuing regulated utility operations. In January 2003, Xcel Energy sold Viking Gas Transmission Co. (Viking), an interstate natural gas pipeline company, including Viking's interest in Guardian Pipeline, LLC. In October 2003, Xcel Energy sold Black Mountain Gas Co. (BMG), a regulated natural gas and propane distribution company. Both Viking and BMG are reported as a component of discontinued operations. In January 2004, Xcel Energy reached an agreement to sell Cheyenne, pending regulatory approval.

Xcel Energy's nonregulated subsidiaries in continuing operations include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), Planergy International, Inc. (energy management solutions) and Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits). During 2003, the board of directors of Xcel Energy approved management's plan to exit businesses conducted by the nonregulated subsidiaries Xcel Energy International Inc. (an international independent power producer, operating primarily in Argentina) and e prime inc. (a natural gas marketing and trading company). Both of these businesses are presented as a component of discontinued operations.

During 2003, Xcel Energy also divested its ownership interest in NRG Energy, Inc. (NRG), an independent power producer. On May 14, 2003, NRG and certain of its affiliates filed voluntary petitions in the U.S. Bankruptcy Court for the Southern District of New York for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. On Dec. 5, 2003, NRG completed its reorganization and emerged from bankruptcy. As a result of the reorganization, Xcel Energy relinquished its ownership interest in NRG. At Dec. 31, 2003, Xcel Energy reports NRG's financial activity as a component of discontinued operations. Xcel Energy is obligated to make payments of up to $752 million to NRG in 2004 and expects to fund these payments with cash on hand and proceeds from a tax refund associated with the write-off of its investment in NRG.

See Note 3 to the Consolidated Financial Statements for further discussion of discontinued operations.

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of 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; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; 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, 2003.

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.

RESULTS OF OPERATIONS

SUMMARY OF FINANCIAL RESULTS

The following table summarizes the earnings contributions of Xcel Energy's business segments on the basis of generally accepted accounting principles (GAAP). Continuing operations consist of the following:

– regulated utility subsidiaries, operating in the electric and natural gas segments; and
– several nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of the following:

– the regulated natural gas businesses Viking and BMG, which were sold in 2003;
– NRG, which emerged from bankruptcy in late 2003, at which time Xcel Energy divested its ownership interest in NRG; and
– the nonregulated subsidiaries Xcel Energy International and e prime, which were classified as held for sale in late 2003 based on the decision to divest them.

Prior-year financial statements have been restated to conform to the current year presentation and classification of certain operations as discontinued. See Note 3 to the Consolidated Financial Statements for a further discussion of discontinued operations.

Contribution to earnings (Millions of dollars)	*2003*	*2002*	*2001*
GAAP income (loss) by segment			
Regulated electric utility segment income – continuing operations	**$462.5**	$ 486.8	$556.0
Regulated natural gas utility segment income – continuing operations	**94.9**	89.0	63.1
Other utility results *(a)*	**6.6**	20.4	18.4
Total utility segment income – continuing operations	**564.0**	596.2	637.5
Other nonregulated results and holding company costs *(a)*	**(54.0)**	(68.5)	(58.3)
Total income – continuing operations	**510.0**	527.7	579.2
Regulated utility income – discontinued operations	**24.3**	10.4	6.0
NRG income (loss) – discontinued operations	**(251.4)**	(3,444.1)	195.1
Other nonregulated income – discontinued operations *(b)*	**339.5**	688.0	2.8
Total income (loss) – discontinued operations	**112.4**	(2,745.7)	203.9
Extraordinary item – net of tax	**–**	–	11.8
Total GAAP income (loss)	**$622.4**	$(2,218.0)	$794.9

Contribution to earnings per share	*2003*	*2002*	*2001*
GAAP earnings per share contribution by segment			
Regulated electric utility segment – continuing operations	**$1.10**	$1.27	$1.62
Regulated natural gas utility segment – continuing operations	**0.23**	0.23	0.19
Other utility results *(a)*	**0.02**	0.05	0.05
Total utility segment earnings per share – continuing operations	**1.35**	1.55	1.86
Other nonregulated results and holding company costs *(a)*	**(0.12)**	(0.18)	(0.18)
Total earnings per share – continuing operations	**1.23**	1.37	1.68
Regulated utility earnings – discontinued operations	**0.06**	0.03	0.02
NRG earnings (loss) – discontinued operations	**(0.60)**	(8.95)	0.56
Other nonregulated earnings – discontinued operations *(b)*	**0.81**	1.78	0.01
Total earnings (loss) per share – discontinued operations	**0.27**	(7.14)	0.59
Extraordinary item	**–**	–	0.03
Total GAAP earnings (loss) per share – diluted	**$1.50**	$(5.77)	$2.30

(a) Not a reportable segment. Included in All Other segment results in Note 20 to the Consolidated Financial Statements.

(b) Includes tax benefit related to NRG. See Note 3 to the Consolidated Financial Statements.

The regulated utility segment contribution to income from continuing operations was lower in 2003 primarily due to higher operating costs and weather impacts, as well as share dilution. The increase in income from discontinued operations in 2003 is largely due to lower NRG-related losses compared with 2002. NRG recorded more than $3 billion of asset impairment and other charges in 2002 as it commenced its financial restructuring. Results from discontinued operations include NRG-related tax benefits in both 2003 and 2002, as discussed in the Discontinued Operations section later.

Common Stock Dilution Dilution, primarily from common stock and convertible securities issued in 2002, reduced the utility segment earnings from continuing operations by 12 cents per share for 2003, compared with average common stock and equivalent levels in 2002. Total earnings from continuing operations were reduced by 11 cents per share for 2003, compared with 2002 share levels. In 2003 and 2002, approximately 418.9 million and 384.6 million average common shares and equivalents, respectively, were used in the calculation of diluted earnings per share.

Because the divestiture of NRG has required its reclassification to discontinued operations in 2003, as discussed later, Xcel Energy is now reporting income from continuing operations in 2003 and 2002. Under accounting requirements, the calculation of diluted earnings per share must be changed for prior periods that reported losses, in which equivalents were previously considered antidilutive. Accordingly, the average common shares assumed in the diluted earnings per share amounts for the third and fourth quarters of 2002, the year 2002 and the first three quarters of 2003 have been recalculated to assume more share dilution and are different from amounts previously reported for those periods. See Note 11 to the Consolidated Financial Statements for further discussion of the calculation of average shares and earnings per share.

STATEMENT OF OPERATIONS ANALYSIS – CONTINUING OPERATIONS

The following discussion summarizes the items that affected the individual revenue and expense items reported in the Statement of Operations.

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. The retail fuel clause cost recovery mechanism in Colorado changed in 2003. For 2002 and 2001, electric utility margins in Colorado reflect the impact of sharing energy costs and savings between customers and shareholders relative to a target cost per delivered kilowatt-hour under the retail incentive cost adjustment (ICA) ratemaking mechanism. For 2003, PSCo is authorized to fully recover its retail electric fuel and purchased energy expense through the interim adjustment clause (IAC). In addition to the IAC, PSCo has other adjustment clauses that allow certain costs to be recovered from retail customers.

Xcel Energy has two distinct forms of electric wholesale sales: short-term wholesale and electric 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 commodity trading refers to the sales for resale activity of purchasing and reselling electric energy to the wholesale market. Short-term wholesale and electric trading activities are considered part of the electric utility segment.

Xcel Energy's electric commodity trading operations are conducted by NSP-Minnesota and PSCo. Margins from electric trading activity 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). PSCo's short-term wholesale and electric trading margins reflect the impact of regulatory sharing, if applicable, of certain margins with Colorado retail customers. Trading revenues, as discussed in Note 1 to the Consolidated Financial Statements, are reported net (i.e., on a margin basis) in the Consolidated Statements of Operations. Trading revenue and costs associated with NRG's operations are included in discontinued operations. Xcel Energy has participated in natural gas commodity trading through e prime, which is now considered a discontinued operation for all periods presented. Consequently, neither NRG nor e prime trading activity is reflected in the following table. The following table details the revenue and margin for base electric utility, short-term wholesale and electric commodity trading activities:

(Millions of dollars)	*Base Electric Utility*	*Short-Term Wholesale*	*Electric Commodity Trading*	*Consolidated Totals*
2003				
Electric utility revenue	**$5,773**	**$179**	**$ –**	**$5,952**
Electric fuel and purchased power – utility	**(2,592)**	**(118)**	**–**	**(2,710)**
Electric trading revenue – gross	**–**	**–**	**333**	**333**
Electric trading costs	**–**	**–**	**(316)**	**(316)**
Gross margin before operating expenses	**$3,181**	**$ 61**	**$17**	**$3,259**
Margin as a percentage of revenue	**55.1%**	**34.1%**	**5.1%**	**51.9%**
2002				
Electric utility revenue	$5,232	$203	$ –	$5,435
Electric fuel and purchased power – utility	(2,029)	(170)	–	(2,199)
Electric trading revenue – gross	–	–	1,529	1,529
Electric trading costs	–	–	(1,527)	(1,527)
Gross margin before operating expenses	$3,203	$ 33	$ 2	$3,238
Margin as a percentage of revenue	61.2%	16.3%	0.1%	46.5%
2001				
Electric utility revenue	$5,607	$788	$ –	$6,395
Electric fuel and purchased power – utility	(2,559)	(613)	–	(3,172)
Electric trading revenue – gross	–	–	1,337	1,337
Electric trading costs	–	–	(1,268)	(1,268)
Gross margin before operating expenses	$3,048	$175	$69	$3,292
Margin as a percentage of revenue	54.4%	22.2%	5.2%	42.6%

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the years ended Dec. 31:

Base Electric Utility Revenue

(Millions of dollars)	***2003 vs. 2002***	*2002 vs. 2001*
Sales growth (excluding weather impact)	**$ 59**	$ 80
Estimated impact of weather	**(29)**	20
Conservation incentive recovery	**–**	(34)
Fuel and purchased power cost recovery	**435**	(414)
Air quality improvement recovery (AQIR)	**36**	–
Capacity sales	**12**	(54)
Rate reductions and customer refunds	**(29)**	28
Renewable development fund recovery	**12**	–
Other	**45**	(1)
Total base electric utility revenue increase (decrease)	**$541**	$(375)

2003 Comparison with 2002 Base electric utility revenues increased due to weather-normalized retail sales growth of approximately 1.5 percent, higher fuel and purchased power costs, which are largely passed through to customers, and higher capacity sales in Texas. In addition, the AQIR was implemented in Colorado in January 2003 for the recovery of investments and related costs to improve air quality. Partially offsetting the higher revenues was the impact of warmer temperatures during the summer of 2002 compared with the summer of 2003, as well as 2003 rate reductions related to lower property taxes in Minnesota and estimated customer refunds related to service quality requirements in Colorado.

2002 Comparison with 2001 Base electric utility revenues decreased due mainly to lower fuel and purchased power costs, which are largely passed through to customers, and lower capacity sales in Texas. In addition, 2002 revenues were lower due to the 2001 allowed recovery of 1998 incentives associated with state-mandated programs for energy conservation. The amounts were previously recorded as liabilities potentially due to Minnesota customers. Partially offsetting the decreases in revenue was weather-normalized retail sales growth of approximately 1.8 percent, the impact of warmer temperatures during the summer of 2002 compared with 2001, and lower 2002 estimated customer refunds related to both service quality requirements in Colorado and property tax refunds in Minnesota.

Base Electric Utility Margin

(Millions of dollars)	***2003 vs. 2002***	*2002 vs. 2001*
Sales growth (excluding weather impact)	**$48**	$ 64
Estimated impact of weather	**(23)**	15
Conservation incentive recovery	**–**	(34)
Purchased capacity costs	**(50)**	(32)
Fuel and purchased power cost recovery	**(41)**	133
AQIR	**28**	–
Capacity sales	**12**	(54)
Rate reductions and customer refunds	**(29)**	28
Renewable development fund recovery	**12**	–
Other	**21**	35
Total base electric utility margin increase (decrease)	**$(22)**	$155

2003 Comparison to 2002 Base electric utility margin decreased due mainly to higher purchased capacity costs associated with new contracts to support growth, the allowed recovery of fuel and purchased power costs in excess of actual costs in 2002 under the sharing provisions of the incentive cost adjustment mechanism in Colorado, compared with passing through costs with no sharing provisions under the IAC in 2003 and the impact of weather. Also decreasing margin were 2003 rate reductions related to lower property taxes in Minnesota and estimated refunds to customers related to service quality requirements in Colorado. The decreases were partially offset by weather-normalized sales growth, the implementation of the AQIR and higher capacity sales, as previously discussed.

2002 Comparison to 2001 Base electric utility margin increased due to weather-normalized retail sales growth, the impact of weather and lower 2002 estimated customer refunds related to both service quality requirements in Colorado and property tax refunds in Minnesota. In addition, the higher base electric margins in 2002 reflect lower unrecovered costs, due in part to resetting the base-energy-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 costs. Partially offsetting the increased margin was the 2001 conservation incentive recovery discussed previously and higher purchased capacity costs due to new contracts to support growth and lower capacity sales in Texas.

Short-Term Wholesale and Electric Commodity Trading Margin

2003 Comparison to 2002 Short-term wholesale and electric commodity trading margins increased approximately $43 million in 2003 compared with 2002. The increase reflects more favorable market conditions in the northern regions.

2002 Comparison to 2001 Short-term wholesale and electric commodity trading sales margins decreased an aggregate of approximately $209 million in 2002, compared with 2001. The decrease in short-term wholesale and electric commodity trading margin reflects less favorable market conditions in the western regions.

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 wholesale natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the wholesale cost of natural gas have little effect on natural gas margin.

(Millions of dollars)	***2003***	*2002*	*2001*
Natural gas utility revenue	**$1,710**	$1,363	$2,023
Cost of natural gas purchased and transported	**(1,208)**	(853)	(1,521)
Natural gas utility margin	**$ 502**	$ 510	$ 502

The following summarizes the components of the changes in natural gas revenue and margin for the years ended Dec. 31:

Natural Gas Revenue

(Millions of dollars)	***2003 vs. 2002***	*2002 vs. 2001*
Sales growth (excluding weather impact)	**$ 15**	$ –
Estimated impact of weather on firm sales volume	**–**	22
Purchased natural gas adjustment clause recovery	**348**	(675)
Rate changes – Colorado	**(14)**	–
Transportation and other	**(2)**	(7)
Total natural gas revenue increase (decrease)	**$347**	$(660)

2003 Comparison to 2002 Natural gas revenue increased mainly due to higher natural gas costs in 2003, which are passed through to customers.

2002 Comparison to 2001 Natural gas revenue decreased mainly due to lower natural gas costs in 2002, which are passed through to customers.

Natural Gas Margin

(Millions of dollars)	***2003 vs. 2002***	*2002 vs. 2001*
Sales growth (excluding weather impact)	**$ 5**	$ –
Estimated impact of weather on firm sales volume	**(4)**	18
Rate changes – Colorado	**(14)**	–
Transportation and other	**5**	(10)
Total natural gas margin increase (decrease)	**$(8)**	$ 8

2003 Comparison to 2002 Natural gas margin decreased due to base rate decreases agreed to in the settlement of the PSCo 2002 general rate case and the impact of warmer winter temperatures in 2003 compared with 2002. The rate case settlement agreement is discussed further under Factors Affecting Results of Continuing Operations. Partially offsetting the rate decrease was weather-normalized sales growth of 1.6 percent.

2002 Comparison to 2001 Natural gas margin increased due mainly to the impact of colder winter temperatures in 2002 compared with 2001.

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. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses, which affects overall results. The impact of weather on earnings is based on the number of customers, temperature variances and the amount of gas or electricity the average customer historically has used per degree of temperature.

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 2003 had minimal impact on earnings per share;
– weather in 2002 increased earnings by an estimated 6 cents per share; and
– weather in 2001 had minimal impact on earnings per share.

Nonregulated Operating Margins

The following table details the changes in nonregulated revenue and margin included in continuing operations:

(Millions of dollars)	***2003***	*2002*	*2001*
Nonregulated and other revenue	**$258**	$235	$237
Nonregulated cost of goods sold	**(157)**	(133)	(128)
Nonregulated margin	**$101**	$102	$109

2003 Comparison to 2002 Nonregulated revenue increased in 2003, due mainly to increasing customer levels in Seren's communication business. Nonregulated margin decreased in 2003, due to higher cost of goods sold at a subsidiary of Utility Engineering offsetting the revenue increases at Seren.

2002 Comparison to 2001 Nonregulated margin decreased in 2002 compared to 2001, due to higher cost of goods sold at a subsidiary of Utility Engineering.

Non-Fuel Operating Expense and Other Items

Other Utility Operating and Maintenance Expense Other utility operating and maintenance expense for 2003 increased by approximately $91 million, or 6.1 percent, compared with 2002. The increase is due primarily to higher employee related costs, including higher performance-based compensation of $36 million, restricted stock unit grants of $29 million, lower pension credits of $19 million and higher medical and health care costs of $9 million. In 2002, there were no restricted stock unit grants and only a partial award of performance-based compensation. In addition, other utility operating and maintenance expense for 2003 reflects inventory write-downs of $8 million, higher uncollectible accounts receivable of $3 million, higher reliability expenses of $6 million and a software project write-off of $2 million. The increase was partially offset by lower information technology costs resulting from centralization.

Other utility operating and maintenance expense for 2002 decreased by approximately $3 million, or 0.2 percent, compared with 2001. The decreased costs reflect lower incentive compensation and other employee benefit costs of $20 million, as well as lower staffing levels in the corporate areas of approximately $11 million due to completion of the corporate merger synergy plans in late 2001. These decreases were substantially offset by higher costs associated with plant outages of $11 million due to planned outages at multiple plants and higher property insurance costs of $9 million due to unfavorable market conditions in 2002, in addition to inflationary factors such as market wage increases and general market inflation.

Other Nonregulated Operating and Maintenance Expense Other nonregulated operating and maintenance expenses decreased $8 million, or 7.7 percent, in 2003 compared with 2002. Other nonregulated operating and maintenance expenses in 2002 increased $20 million, or 22.8 percent, compared with 2001. The 2002 expenses included employee severance costs at the holding company. These expenses are included in the results for each nonregulated subsidiary, as discussed later.

Depreciation and Amortization Expense Depreciation and amortization expense decreased by approximately $15 million, or 2.0 percent, for 2003, compared with 2002. This decrease reflects the impacts of nuclear plant life extensions at Prairie Island and certain depreciation rate changes in Colorado, partially offset by increasing depreciation related to plant additions. The increase in depreciation and amortization in 2002 compared with 2001 is also due to the impacts of plant additions.

In December 2003, the Minnesota Public Utilities Commission (MPUC) extended the authorized useful lives of the two NSP-Minnesota generating units at the Prairie Island nuclear plant until 2013 and 2014, respectively. The recovery was effective Jan. 1, 2003, and the net effect on depreciation and amortization, partially offset by revisions to nuclear decommissioning accrual, was a $22 million decrease in depreciation expense. In addition, effective July 1, 2003, the Colorado Public Utilities Commission (CPUC) lengthened the depreciable lives of certain electric utility plant at PSCo as a part of the general Colorado rate case, which will reduce annual depreciation expense by $20 million and reduced 2003 depreciation expense by approximately $10 million.

Special Charges Special charges reported in 2003 relate to the TRANSLink project and NRG restructuring costs. Special charges for 2002 include NRG restructuring costs, as discussed later, but are largely related to regulated utility costs as discussed in the following paragraph. All 2001 special charges relate to utility costs. See Note 2 to the Consolidated Financial Statements for further discussion of these items.

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 for utility and service company operations. Regulated utility earnings from continuing operations in 2001 were lower 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 post-employment 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.

Interest and Other Income, Net of Nonoperating Expenses Interest and other income, net of nonoperating expenses decreased $9 million in 2003 compared with 2002. Interest income decreased $13 million in 2003 compared with 2002 primarily due to interest received on tax refunds in 2002. Other income decreased $11 million primarily due to a gain on the sale of contracts at Planergy in 2002. Partially offsetting these decreases was an increase in allowance for funds used during construction resulting from lower levels of short-term debt used to finance utility construction.

Interest and other income, net of nonoperating expenses increased $14 million from 2002 compared with 2001. Interest income increased by $8 million primarily due to interest received on tax refunds in 2002. Other income increased by $13 million, primarily due to a gain on the sale of contracts at Planergy in 2002. Partially offsetting these increases was a decrease in the gain on disposal of assets of $5 million due to a gain recorded in 2001 by PSCo.

Interest and Financing Costs Interest and financing costs increased approximately $30 million, or 7.1 percent, for 2003 compared with 2002. This increase was due to the full-year impact of the issuance of long-term debt in the latter part of 2002 intended to reduce dependence on short-term debt. In addition, during the fourth quarter of 2002, Xcel Energy incurred approximately $15 million to redeem temporary holding company debt.

During 2003, Xcel Energy issued approximately $1.7 billion of long-term debt to refinance higher coupon debt. These actions are expected to reduce 2004 interest costs by approximately $15 million compared with 2003 levels.

Interest and financing costs increased $56 million, or 15.3 percent, in 2002 compared with 2001. During 2002, certain long-term debt was refinanced at higher interest rates. Additionally, certain redemption costs were incurred, as noted previously.

Income Tax Expense Income tax expense decreased by approximately $77 million in 2003, compared with a decrease of $69 million in 2002. The effective tax rate for 2003 was 23.7 percent, compared with 30.9 percent in 2002. The decrease in the effective rate in 2003 was due largely to approximately $36 million of tax adjustments recorded mainly in the fourth quarter of 2003 to reflect the successful resolution of various outstanding tax issues related to prior years. The tax issues resolved during 2003 included the tax deductibility of certain merger costs associated with the merger to form Xcel Energy and NCE and the deductibility, for state purposes, of certain tax benefit transfer lease benefits. Tax expense also decreased in 2003 due to lower income levels in 2003. The decrease in 2002 was due primarily to increased tax credits and lower pretax income in 2002. See Note 10 to the Consolidated Financial Statements.

Other Nonregulated Subsidiaries and Holding Company Results

The following tables summarize the net income and earnings-per-share contributions of the continuing operations of Xcel Energy's nonregulated businesses and holding company results:

Contribution to Xcel Energy's earnings (Millions of dollars)	***2003***	*2002*	*2001*
Eloigne Company	**$ 7.7**	$ 8.0	$ 8.7
Seren Innovations	**(18.4)**	(27.0)	(26.8)
Planergy	**(7.7)**	(1.7)	(12.0)
Financing costs – holding company	**(44.1)**	(47.4)	(34.0)
Special charges – holding company	**(11.2)**	(2.9)	–
Other nonregulated and holding company results	**19.7**	2.5	5.8
Total nonregulated/holding company earnings (loss) – continuing operations	**$(54.0)**	$(68.5)	$(58.3)

Contribution to Xcel Energy's earnings per share	***2003***	*2002*	*2001*
Eloigne Company	**$ 0.02**	$ 0.02	$ 0.03
Seren Innovations	**(0.04)**	(0.07)	(0.08)
Planergy	**(0.02)**	–	(0.04)
Financing costs and preferred dividends – holding company	**(0.09)**	(0.13)	(0.11)
Special charges – holding company	**(0.03)**	(0.01)	–
Other nonregulated and holding company results	**0.04**	0.01	0.02
Total nonregulated/holding company earnings (loss) per share – continuing operations	**$(0.12)**	$(0.18)	$(0.18)

Eloigne Company Eloigne invests in affordable housing that qualifies for Internal Revenue Service tax credits. Eloigne's earnings contribution declined slightly in 2003 and 2002 as tax credits on mature affordable housing projects began to decline.

Seren Innovations Seren operates a combination cable television, telephone and high-speed Internet access system in St. Cloud, Minn., and Contra Costa County, Calif. Operation of its broadband communications network has resulted in losses. Seren has completed its build-out phase and has been experiencing improvement in its operating results. Neutral cash flow is expected in 2004 and positive cash flow is projected for 2005. A positive earnings contribution is anticipated in 2007, assuming customer addition goals are met.

Planergy Planergy provides energy management services. Planergy's losses were lower in 2002 largely due to pretax gains of approximately $8 million from the sale of a portfolio of energy management contracts, which reduced losses by approximately 2 cents per share.

Financing Costs and Preferred Dividends Nonregulated results include interest expense and the earnings-per-share impact of 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 long-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.

Financing costs and preferred dividends per share for 2003 included above reflect the impact of dilutive securities, as discussed further in Note 11 to the Consolidated Financial Statements. The impact of the dilutive securities, if converted, is a reduction of interest expense of approximately $11 million, or 3 cents per share.

Holding Company Special Charges During 2002, NRG experienced credit-rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events ultimately led to the restructuring of NRG in late 2002 and its bankruptcy filing in May 2003. See Note 4 to the Consolidated Financial Statements. Certain costs related to NRG's restructuring were incurred at the holding company level and included in continuing operations and reported as Special Charges. Approximately $12 million of these costs were incurred in 2003 and $5 million were incurred in 2002, which reduced after-tax earnings by approximately 2 cents per share and 1 cent per share, respectively. Costs in 2003 included approximately $32 million of financial advisor fees, legal costs and consulting costs related to the NRG bankruptcy transaction. These charges were partially offset by a $20 million pension curtailment gain related to the termination of NRG employees from Xcel Energy's pension plan. In 2003, Xcel Energy also recorded a $7 million charge in connection with the suspension of the formation of the independent transmission company TRANSLink Transmission Co., LLC (TRANSLink). See Note 2 to the Consolidated Financial Statements for further discussion of these special charges.

Other Nonregulated In 2003, Utility Engineering sold water rights, resulting in a pretax gain (reported as nonoperating income) of $15 million. The gain increased after-tax income by approximately 2 cents per share.

STATEMENT OF OPERATIONS ANALYSIS – DISCONTINUED OPERATIONS

A summary of the various components of discontinued operations is as follows for the years ended Dec. 31:

(Millions of dollars)	***2003***	*2002*	*2001*
Income (loss)			
Viking Gas Transmission Co.	**$ 21.9**	$ 9.4	$ 5.0
Black Mountain Gas	**2.4**	1.0	1.0
Regulated natural gas utility segment – income	**24.3**	10.4	6.0
NRG segment – income (loss)	**(251.4)**	(3,444.1)	195.1
Xcel Energy International	**(45.5)**	(17.1)	(2.9)
e prime	**(17.8)**	1.5	8.0
Other	**(1.6)**	(2.4)	(2.3)
NRG-related tax benefits	**404.4**	706.0	–
Nonregulated/other – income	**339.5**	688.0	2.8
Total income (loss) from discontinued operations	**$112.4**	$(2,745.7)	$203.9
Earnings (loss) per share			
Viking Gas Transmission Co.	**$ 0.05**	$ 0.03	$ 0.02
Black Mountain Gas	**0.01**	–	–
Regulated natural gas utility segment – income per share	**0.06**	0.03	0.02
NRG segment – income (loss) per share	**(0.60)**	(8.95)	0.56
Xcel Energy International	**(0.11)**	(0.05)	(0.01)
e prime	**(0.04)**	–	0.02
NRG-related tax benefits	**0.96**	1.83	–
Nonregulated/other – income per share	**0.81**	1.78	0.01
Total income (loss) per share from discontinued operations	**$ 0.27**	$ (7.14)	$ 0.59

Regulated Natural Gas Utility Results – Discontinued Operations

During 2003, Xcel Energy completed the sale of two subsidiaries in its regulated natural gas utility segment: Viking, including its interest in Guardian Pipeline, LLC, and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded for the natural gas utility segment, primarily related to the sale of Viking.

Viking had minimal income in 2003, as it was sold in January of that year. Income from Viking was higher in 2002 compared with 2001 primarily due to increased revenues.

NRG Results – Discontinued Operations

Due to NRG's emergence from bankruptcy in December 2003 and Xcel Energy's corresponding divestiture of its ownership interest in NRG, Xcel Energy's share of NRG results for current and prior periods is now shown as a component of discontinued operations.

2003 NRG Results Compared with 2002 As a result of NRG's bankruptcy filing in May 2003, Xcel Energy ceased the consolidation of NRG and began accounting for its investment in NRG using the equity method in accordance with Accounting Principles Board Opinion No. 18 – "The Equity Method of Accounting for Investments in Common Stock." After changing to the equity method, Xcel Energy was limited in the amount of NRG's losses subsequent to the bankruptcy date that it was required to record. In accordance with these limitations under the equity method, Xcel Energy stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provided for loss recognition by Xcel Energy until its investment in NRG was written off to zero, with further loss recognition to continue if its financial commitments to NRG exist beyond amounts already invested. Xcel Energy initially recorded more losses than the limitations allow as of June 30, 2003, but upon Xcel Energy's divestiture of its interest in NRG, the NRG losses recorded in excess of Xcel Energy's investment in and financial commitment to NRG were reversed in the fourth quarter of 2003. This resulted in a noncash gain of $111 million, or 26 cents per share, for the quarter and an adjustment of the total NRG losses recorded for the year 2003 to $251 million, or 60 cents per share.

NRG's results included in Xcel Energy's earnings for 2003 were as follows:

(Millions of dollars)	*Six months ended June 30, 2003*
Total NRG loss	$(621)
Losses not recorded by Xcel Energy under the equity method*	370
Equity in losses of NRG included in Xcel Energy results for 2003	$(251)

** These represent NRG losses incurred in the first and second quarters of 2003 that were in excess of the amounts recordable by Xcel Energy under the equity method of accounting limitations discussed previously.*

Following its credit downgrade in July 2002, NRG experienced credit and liquidity constraints and commenced a financial and business restructuring, including a voluntary petition for bankruptcy protection. This restructuring created significant incremental costs and resulted in numerous asset impairments as the strategic and economic value of assets under development and in operation changed.

NRG's asset impairments and related charges in 2003 include approximately $40 million in first-quarter charges related to NRG's NEO landfill gas projects and equity investments, and approximately $500 million was recorded in the second quarter. The impairment and related charges in the second quarter of 2003 resulted from planned disposals of the Loy Yang project in Australia and the McClain and Brazos Valley projects in the United States, and regulatory developments and changing circumstances throughout the second quarter that adversely affected NRG's ability to recover the carrying value of certain Connecticut merchant generation units. As of the bankruptcy filing date (May 14, 2003), Xcel Energy had recognized $263 million of NRG's impairments and related charges for the Connecticut facilities and Brazos Valley as these charges were recorded by NRG prior to May 14, 2003. Consequently, Xcel Energy recorded its equity in NRG results for the second quarter (including these impairments) in excess of its financial commitment to NRG under the settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG's creditors. These excess losses were reversed upon NRG's emergence from bankruptcy in December 2003, as discussed previously.

In 2003, NRG's operating results (excluding the unusual items discussed above) were affected by higher market prices due to higher natural gas prices and an increase in capacity revenues due to additional projects becoming operational in the later part of 2002. In addition, the sale of an NRG investment in 2002 resulted in a favorable impact in 2003 as the investment generated substantial equity losses in the prior years. The increase was offset by losses incurred on contracts in Connecticut due to increased market prices, increased operating expenses, contract terminations and liquidated damages triggered by NRG's financial condition and additional restructuring charges.

During 2002, the tax filing status of NRG for 2002 and future years changed from being included as part of Xcel Energy's consolidated federal income tax group to filing on a stand-alone basis. On a stand-alone basis, NRG did not have the ability to recognize all tax benefits that may ultimately accrue from its 2003 operating losses and is currently in a net operating loss carry forward position for tax purposes. Accordingly, NRG's results for 2003 include no material tax effects.

2002 NRG Results Compared with 2001 NRG losses in 2002 were $3.4 billion, or $8.95 per share, due primarily to asset impairment charges and estimated disposal losses of more than $3 billion and other charges recorded in the third and fourth quarters of 2002 related to NRG's financial restructuring. Also, NRG recorded other incremental costs related to its financial restructuring and business realignment.

During 2002, NRG's 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. In addition, increased administrative costs, depreciation and interest expense from completed construction contributed to the less-than-favorable results for NRG in 2002.

As discussed previously, on a stand-alone basis, NRG did 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, which included income related to recognition of tax credits.

See Notes 3 and 4 to the Consolidated Financial Statements for further discussion of the 2003 change in accounting for NRG, Xcel Energy's limitation for recognizing NRG's losses due to its bankruptcy filing and further discussion of NRG's results included in discontinued operations, including asset impairment charges.

Other Nonregulated Results – Discontinued Operations

During 2003, the board of directors of Xcel Energy approved management's plan to exit the businesses conducted by its nonregulated subsidiaries, Xcel Energy International and e prime. Xcel Energy is in the process of marketing the assets and operations of these businesses to prospective buyers and expects to exit the businesses during 2004.

2003 Nonregulated Results Compared with 2002 Results of discontinued nonregulated operations, other than NRG, include an after-tax loss of $59 million, or 14 cents per share, expected on the disposal of Xcel Energy International's assets, based on the estimated fair value of such assets. Xcel Energy's remaining investment in Xcel Energy International at Dec. 31, 2003, was approximately $39 million. These losses from discontinued nonregulated operations also include a charge of $16 million for costs of settling a Commodity Futures Trading Commission trading investigation of e prime.

2002 Nonregulated Results Compared with 2001 Nonregulated and holding company earnings for 2002 were reduced by impairment losses recorded by Xcel Energy International for Argentina assets and disposal losses for Yorkshire Power. In 2002, Xcel Energy International 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 Energy International's investment. The write-down for this Argentina facility was approximately $13 million, or 3 cents per share.

In August 2002, Xcel Energy announced it had sold Xcel Energy International's 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. Xcel Energy International and American Electric Power Co. 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. 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.

Tax Benefits Related to Investment in NRG With NRG's emergence from bankruptcy in December 2003, Xcel Energy has divested its ownership interest in NRG and plans to take a loss deduction in 2003. These benefits, since related to Xcel Energy's investment in discontinued NRG operations, are also reported as discontinued operations. During 2002, Xcel Energy recognized an initial estimate of the expected tax benefits of $706 million. This benefit was based on the estimated tax basis of Xcel Energy's cash and stock investments already made in NRG, and their deductibility for federal income tax purposes.

Based on the results of a 2003 study, Xcel Energy recorded $105 million of additional tax benefits in the third quarter of 2003, reflecting an updated estimate of the tax basis of Xcel Energy's investments in NRG and state tax deductibility. Upon NRG's emergence from bankruptcy, an additional $288 million of tax benefit was recorded in the fourth quarter of 2003 to reflect the deductibility of expected settlement payments of $752 million, uncollectible receivables from NRG, other state tax benefits and further adjustments to the estimated tax basis in NRG. Another $11 million of state tax benefits were accrued earlier in 2003 based on projected impacts.

Based on current forecasts of taxable income and tax liabilities, Xcel Energy expects to realize approximately $1.1 billion of cash savings from these tax benefits through a refund of taxes paid in prior years and reduced taxes payable in future years. Xcel Energy used $130 million of these tax benefits in 2003 and expects to use $480 million in 2004. The remainder of the tax benefit carry forward is expected to be used over subsequent years.

EXTRAORDINARY ITEM – ELECTRIC UTILITY RESTRUCTURING

In 2001, SPS recorded extraordinary income of $18 million before tax, or 3 cents per share, related to the regulated utility business to reflect the impacts of industry restructuring developments for SPS. This represented a reversal of a portion of an extraordinary loss recorded in 2000 related to industry restructuring. For more information on this 2001 extraordinary item, see Note 14 to the Consolidated Financial Statements.

FACTORS AFFECTING RESULTS OF CONTINUING 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 and affect our ability to recover our costs from customers. In addition, Xcel Energy's nonregulated businesses have had an adverse impact on Xcel Energy's earnings in 2003 and 2002. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including the following:

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. The United States economy is showing recent signs of recovery as measured by growth in the gross domestic product. However, certain operating costs, such as insurance and security, have increased due to economic uncertainty, terrorist activity and war or the threat of war. Management cannot predict the impact of a future economic slowdown, fluctuating energy prices, war or the threat of war. However, Xcel Energy could experience a material adverse impact to its results of operations, future growth or ability to raise capital from a stalled economic recovery.

Sales Growth

In addition to the impact of weather, 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 1.5 percent in 2003 compared with 2002, and 1.8 percent in 2002 compared with 2001. Weather-normalized sales growth for firm gas utility customers was estimated to be approximately 1.6 percent in 2003 compared with 2002, and relatively flat in 2002 compared with 2001. Projections indicate that weather-normalized sales growth in 2004 compared with 2003 will be approximately 2.2 percent for retail electric utility customers and 2.4 percent for firm 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 in the past has been significant as utilities combined to capture economies of scale or establish a strategic niche in preparing for the future, although such activity slowed substantially after 2001. All utilities were required to provide nondiscriminatory access to the use of their transmission systems in 1996. In addition, the FERC issued a series of regulatory orders in 2003. These orders, among other things, standardized the methods and pricing of power generation interconnections, established new standards of conduct rules for transmission providers and new code of conduct rules for utilities with market-based rate authority. Xcel Energy has not yet estimated the full impact of the new FERC regulatory orders, but it could be material.

Some states had begun to allow retail customers to choose their electricity supplier, while other states have delayed or canceled industry restructuring. There were no significant retail electric or natural gas restructuring efforts in the states served by Xcel Energy in 2003.

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 the financial position, results of operations and cash flows of Xcel Energy.

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 12 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 in 2000, 2001 and 2002 and decreases in interest rates used to discount benefit obligations. While investment returns exceeded the assumed level of 9.25 percent in 2003, investment returns in 2001 and 2002 were below the assumed level of 9.5 percent and discount rates have declined from the 7.25-percent to 8-percent levels used in 1999 through 2002 cost determinations to 6.75 percent used in 2003. Xcel Energy continually reviews its pension assumptions and, in 2004, expects to change the investment return assumption to 9.0 percent and the discount rate assumption to 6.25 percent.

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 9.0 percent in each future year and holding other assumptions constant, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes in continuing operations will increase from a credit, or negative expense, of $51 million in 2003 to a credit of $25 million in 2004 and zero 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, 2003, the annualized Moody's Aa index rate, roughly in the middle of the Aaa and Baa range, declined by about 0.5 percent from the prior year end, which resulted in a corresponding decrease from 6.75 percent at year-end 2002 to a 6.25-percent pension discount rate at year-end 2003. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2004 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 100 basis point higher rate of return, 10.0 percent, would decrease 2004 pension costs by $18.4 million;
- a 100 basis point lower rate of return, 8.0 percent, would increase 2004 pension costs by $18.4 million;
- a 100 basis point higher discount rate, 7.25 percent, would decrease 2004 pension costs by $9.5 million; and
- a 100 basis point lower discount rate, 5.25 percent, would increase 2004 pension costs by $8.8 million.

Alternative Employee Retirement Income Security Act of 1974 (ERISA) funding assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be affected by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in recent years for Xcel Energy's pension plans, and do not require funding in 2004. Assuming that future asset return levels equal the actuarial assumption of 9.0 percent for the years 2004 and 2005, Xcel Energy projects, under current funding regulations, that cash funding would be required in the amount of approximately $0 million for 2005 and $15 million for 2006. Actual performance can affect these funding requirements significantly. Current funding regulations were under legislative review in 2004 and, if not retained in their current form, could change these funding requirements materially. To begin meeting these projected funding requirements, PSCo elected to make a voluntary contribution of $30 million to its pension plan for bargaining employees in 2003, and it plans to voluntarily contribute another $10 million to the plan in 2004.

Regulation

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.

Xcel Energy's utility subsidiaries also are regulated by the FERC and state regulatory commissions. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing energy market and general economic conditions.

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 rates 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 purchased 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 interim adjustment clause that allows for recovery of all prudently incurred electric fuel and purchased energy expenses in 2003. In 2004, PSCo generally is expected to recover all prudently incurred electric fuel and purchased energy costs through an electric commodity adjustment clause. Additionally, this fuel mechanism also has in place a sharing among customers and shareholders of certain fuel and energy costs, with an $11.25 million maximum on any cost sharing over or under an allowed electric commodity adjustment formula rate, and a sharing among shareholders and customers of certain gains and losses on trading margins.

Xcel Energy's utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy distribution system. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, in 2003 approval was obtained from Colorado and Minnesota regulators to recover, through a rate surcharge, certain costs to upgrade plants and lower emissions in the Denver and Minneapolis-St. Paul metropolitan areas. These rate recovery mechanisms are expected to provide significant cash flows to enable recovery of costs incurred on a timely basis.

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 effect on Xcel Energy's results of operations in the period the write-off is recorded.

At Dec. 31, 2003, Xcel Energy reported on its balance sheet regulatory assets of approximately $572 million and regulatory liabilities of approximately $1.2 billion 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. See Notes 1 and 19 to the Consolidated Financial Statements for further discussion of regulatory deferrals.

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 as required in the merger approval agreement with the CPUC to form Xcel Energy. On April 4, 2003, a comprehensive settlement agreement was reached, which addressed all significant issues in the rate case. In mid-2003, the CPUC approved the final settlement, which provided for:

- a decrease in annual base rates of approximately $33 million for natural gas and $230,000 for electricity, including an annual reduction to electric depreciation expense of approximately $20 million, effective July 1, 2003;
- an interim adjustment clause (IAC) that fully recovers prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates during 2003;
- a new electric commodity adjustment clause (ECA) for 2004 through 2006, with an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate; and
- an authorized return on equity of 10.75 percent for electric operations and 11.0 percent for natural gas and thermal energy operations.

PSCo Performance-Based Regulatory Plan (PBRP) The 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 an 11-percent return on equity for 2001 and a 10.50-percent return on equity for 2002;
  - no earnings sharing for 2003 as PSCo established new rates in its general rate case; and
  - an annual electric earnings test with the sharing of earnings in excess of the return on equity for electric operations of 10.75 percent for 2004 through 2006;
- an electric quality of service plan (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; and
- 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.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually.

- In 2001, PSCo did not earn a return on equity in excess of 11 percent and met the electric and gas QSP benchmarks. The CPUC has accepted the QSP components of the PBRP filing and approved the earnings test.
- In 2002, PSCo did not earn a return on equity in excess of 10.5 percent, so no refund liability has been recorded. Both electric and gas QSP benchmarks were met. Therefore, no liability has been recorded for the earnings test. A CPUC decision is pending. The CPUC is considering whether PSCo's cost of debt has been adversely affected by the financial difficulties of NRG, and if so, whether any adjustments to PSCo's cost of capital should be made. A hearing has been set for August 2004.
- The 2003 QSP results will be filed in April 2004. An estimate of customer refund obligations under the electric QSP plan was recorded in 2003 relating to the electric service unavailability and customer complaint measures. No refund under the gas QSP is anticipated.

In 2003, PSCo filed an application to put into effect a purchased-capacity cost-adjustment mechanism that would allow it to recover 100 percent of its incremental purchased-capacity costs over the level of these costs in rates. As a part of this application, PSCo proposed to modify the PBRP for 2004 through 2006 to provide that 100 percent of any earnings in excess of a 10.75-percent return on equity for electric operations be returned to customers. The application is pending approval of the CPUC.

Tax Matters

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. Xcel Energy plans to challenge the IRS determination, which could require several years to reach final resolution. Because it is Xcel Energy's position that the IRS determination is not supported by tax law, Xcel Energy has not recorded any provision for income tax or interest expense related to this matter and continues to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. However, defense of PSCo'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 1993 through 1997 is approximately $175 million. Additional interest expense deductions for the period 1998 through 2003 are estimated to total approximately $404 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2003, would reduce earnings by an estimated $254 million, after tax. If COLI interest expense deductions were no longer available, annual earnings for 2004 would be reduced by an estimated $36 million, after tax, prospectively, which represents 9 cents per share using 2003 share levels.

Environmental Matters

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 operating expenses for environmental monitoring and disposal of hazardous materials and wastes were approximately:

- $133 million in 2003;
- $138 million in 2002; and
- $130 million in 2001.

Xcel Energy expects to expense an average of approximately $155 million per year from 2004 through 2008 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 regulated facilities were approximately:
– $58.5 million in 2003;
– $107.8 million in 2002; and
– $135.7 million in 2001.

The regulated utilities expect to incur approximately $83.0 million in capital expenditures for compliance with environmental regulations in 2004 and approximately $1.1 billion for environmental improvements during the period from 2004 through 2008. Approximately $43 million and $988 million of these expenditures, respectively, are related to modifications to reduce the emissions of NSP-Minnesota's generating plants located in the Minneapolis-St. Paul metropolitan area pursuant to the metropolitan emissions reduction project (MERP), which are recoverable from customers through cost recovery mechanisms. See Notes 17 and 18 to the Consolidated Financial Statements for further discussion of our environmental contingencies.

Impact of Nonregulated Investments

Xcel Energy's investments in nonregulated operations have had a significant impact on its results of operations. As a result of the divestiture of NRG, Xcel Energy does not expect that its investments in nonregulated operations will continue to have such a significant impact on its results. Xcel Energy does not expect to make any material investments in nonregulated projects. Xcel Energy's remaining nonregulated businesses may carry a higher level of risk than its traditional utility businesses.

Xcel Energy's earnings from nonregulated subsidiaries include investments in broadband communications systems through Seren. Management currently intends to hold and operate the Seren broadband communications system investments. As of Dec. 31, 2003, Xcel Energy's investment in Seren was approximately $265 million. Seren had capitalized $331 million for plant in service and had incurred another $10 million for construction work in progress for these systems at Dec. 31, 2003.

Xcel Energy has also invested in international projects, primarily in Argentina, through Xcel Energy International, but has designated Xcel Energy International as held for sale as of Dec. 31, 2003. An estimated after-tax loss from disposal of Xcel Argentina assets of $59 million has been recorded, but may change as the final impacts of the divestiture become known in 2004.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders.

Critical Accounting Policies and Estimates

Preparation of the Consolidated Financial Statements and related disclosures in compliance with 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 potential likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been discussed with the audit committee of the Xcel Energy board of directors. Xcel Energy no longer considers NRG's financial restructuring a critical accounting policy due to the divestiture resulting from NRG's emergence from bankruptcy.

Accounting Policy	*Judgments/Uncertainties Affecting Application*	*See Additional Discussion At*
Regulatory Mechanisms and Cost Recovery	– External regulatory 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 Continuing Operations Utility Industry Changes Regulation Notes to Consolidated Financial Statements Notes 1, 17 and 19
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, 17 and 18

Accounting Policy	*Judgments/Uncertainties Affecting Application*	*See Additional Discussion At*
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 Continuing Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 10 and 17
Benefit Plan Accounting	– Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition – Discount 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 Continuing Operations Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements Notes 1 and 12
Asset Valuation	– Regional economic conditions affecting asset operation, market prices and related cash flows – Foreign currency valuations changes – Regulatory and political environments and requirements – Levels of future market penetration and customer growth	Management's Discussion and Analysis: Results of Operations Statement of Operations Analysis – Discontinued Operations Factors Affecting Results of Continuing Operations Impact of Nonregulated Investments Notes to Consolidated Financial Statements Note 3

Xcel Energy continually makes informed judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. For example:

- probable outcomes of regulatory proceedings are assessed in cases of requested cost recovery or other approvals from regulators;
- the ability to operate plant facilities and recover the related costs over their useful operating lives, or such other period designated by our regulators, is assumed;
- probable outcomes of reviews and challenges raised by tax authorities, including appeals and litigation where necessary, are assessed;
- returns are projected regarding earnings on pension investments, and the salary increases provided to employees over their periods of service; and
- future cash inflows of operations are projected in order to assess whether they will be sufficient to recover future cash outflows, including the impacts of product price changes and market penetration to customer groups.

The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impacts of these factors as of Dec. 31, 2003.

Recently Implemented Accounting Changes

For a discussion of accounting changes implemented in 2003 and other significant accounting policies, see Notes 1, 16 and 18 to the Consolidated Financial Statements.

Pending Accounting Changes

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the Financial Accounting Standards Board (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, consolidation has been required only for subsidiaries in which an enterprise has a majority voting interest. Under FIN No. 46, an enterprise's consolidated financial statements will include the consolidation of variable interest entities, which are entities in which the enterprise has a controlling financial interest. As a result, Xcel Energy expects that it will be required to consolidate all or a portion of its affordable housing investments made through Eloigne, which currently are accounted for under the equity method. The Xcel Energy utility subsidiaries are party to purchased power agreements, and based on the current guidance, these contracts are not expected to be considered variable interest arrangements under the provisions of FIN No. 46. However, Xcel Energy is still evaluating the issue. Additionally, Xcel Energy is evaluating other arrangements based on criteria in FIN No. 46, and it is likely that some arrangements will require consolidation.

As of Dec. 31, 2003, the assets of the affordable housing investments were approximately $142 million and long-term liabilities were approximately $78 million. Currently, investments of $56 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2003, 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, 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. Xcel Energy plans to adopt FIN No. 46 in the first quarter of 2004. The impact of consolidating these entities is not expected to have a material impact on net income.

DERIVATIVES, RISK MANAGEMENT AND MARKET RISK

Business and Operational Risk Xcel Energy and its subsidiaries, including discontinued operations held for sale, 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 are exposed 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 Xcel Energy uses various physical contracts and derivative instruments to reduce the volatility in the cost of natural gas and electricity provided to 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 have been 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, primarily through NRG and Xcel Energy International. With the divestiture of NRG and expected sale of Xcel Energy International, the exposure to market price risk has greatly diminished. Xcel Energy managed this market price risk by entering into firm power sales agreements for approximately 55 percent 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, Xcel Energy managed 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 for the management of market price risks, and provides guidelines for the level of price risk exposure that is acceptable within the company's operations.

Interest Rate Risk Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

Xcel Energy engages in hedges of cash flow exposure and hedges of fair value exposure. The fair value of interest rate swaps designated as cash flow hedges are initially recorded in Other Comprehensive Income. Reclassification of unrealized gains or losses on cash flow hedges of variable rate debt instruments from Other Comprehensive Income into earnings occurs as interest payments are accrued on the debt instrument and generally offsets the change in the interest accrued on the underlying variable rate debt. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or firm commitment. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments. In order to test the effectiveness of such swaps, a hypothetical swap is used to mirror all the critical terms of the underlying debt and regression analysis is utilized to assess the effectiveness of the actual swap at inception and on an ongoing basis. The assessment is done periodically to ensure the swaps continue to be effective. The fair value of interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

At Dec. 31, 2003 and 2002, a 100-basis-point change in the benchmark rate on Xcel Energy's variable debt would impact net income by approximately $0.8 million and $12.6 million, respectively. See Note 15 to the Consolidated Financial Statements for a discussion of Xcel Energy and its subsidiaries' interest rate swaps.

Currency Exchange Risk During 2003 and 2002, NRG and Xcel Energy International, both of which are included in discontinued operations, held certain investments in foreign countries, creating exposure to foreign currency exchange risk. The foreign currency exchange risk included the risk relative to the recovery of the net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. These subsidiaries managed their 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.

Trading Risk Xcel Energy's subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and, prior to December 2003, through e prime for natural gas. The trading operations are conducted in the United States 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 the energy trading contracts of continuing operations as of Dec. 31, 2003 was as follows:

(Millions of dollars)	
Fair value of trading contracts outstanding at Jan. 1, 2003	**$ (0.1)**
Contracts realized or settled during the year	**(14.4)**
Fair value of trading contract additions and changes during the year	**18.7**
Fair value of contracts outstanding at Dec. 31, 2003	**$ 4.2**

As of Dec. 31, 2003, the sources of fair value of the energy trading and hedging net assets were as follows:

Trading Contracts

				Futures/Forwards		
(Thousands 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 Futures/ Forwards Fair Value*
NSP-Minnesota	*1*	$ (143)	$ –	$ –	$ –	$ (143)
	2	3,163	486	–	–	3,649
PSCo	*1*	(69)	–	–	–	(69)
	2	693	36	–	–	729
Total futures/forwards fair value		$3,644	$522	$ –	$ –	$4,166

Discontinued operations trading contracts are not included in the above table. The fair value of these contracts is approximately $(2.0) million, as of Dec. 31, 2003. All of these contracts have maturities of less than one year.

Hedge Contracts

				Futures/Forwards		
(Thousands 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 Futures/ Forwards Fair Value*
NSP-Minnesota futures/forwards fair value	*2*	$ 569	$ –	$ –	$ –	$ 569

Discontinued operations hedging contracts are not included in the above table. As of Dec. 31, 2003, the fair value of these contracts is approximately $1.5 million. All of these contracts have maturities of less than one year.

				Options		
(Thousands 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 Options Fair Value*
NSP-Minnesota	*2*	$ (1,287)	$ –	$ –	$ –	$ (1,287)
NSP-Wisconsin	*2*	168	–	–	–	168
PSCo	*2*	(11,466)	848	–	–	(10,618)
Total options fair value		$(12,585)	$848	$ –	$ –	$(11,737)

1 *Prices actively quoted or based on actively quoted prices.*

2 *Prices based on models and other valuation methods. These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of energy commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the model.*

In the above tables, only hedge transactions are included for NSP-Minnesota, NSP-Wisconsin and PSCo. Normal purchases and sales transactions, as defined by SFAS No. 133, have been excluded.

At Dec. 31, 2003, a 10-percent fluctuation in market prices over the next 12 months for trading contracts would impact pretax income from continuing operations by approximately $1 million. Hedge contracts are accounted for as a component of Other Comprehensive Income and would not directly impact earnings.

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, delta half-gamma approach for non-linear instruments and various holding periods varying from two to five days.

As of Dec. 31, 2003, the calculated VaRs were:

(Millions of dollars)	*Year ended Dec. 31, 2003*	*Average*	*During 2003 High*	*Low*
Electric commodity trading *(a)*	**$ 0.92**	**$ 0.70**	**$ 1.51**	**$ 0.29**
Natural gas commodity trading *(b)*	**$ –**	**$ 0.06**	**$ 0.89**	**$ –**
Natural gas retail marketing *(b)*	**$ 0.08**	**$ 0.32**	**$ 1.00**	**$ 0.02**
Other	**$ –**	**$ 0.02**	**$ 0.15**	**$ –**

(a) Comprises transactions for both NSP-Minnesota and PSCo.

(b) Conducted by e prime, which is a discontinued operation held for sale.

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 *(a)*	$ 0.29	$ 0.62	$ 3.39	$ 0.01
Natural gas commodity trading *(c)*	$ 0.11	$ 0.35	$ 1.09	$ 0.09
Natural gas retail marketing *(c)*	$ 0.54	$ 0.47	$ 0.92	$ 0.32
NRG power marketing *(b)*	$118.60	$76.20	$124.40	$42.00

(a) Comprises transactions for both NSP-Minnesota and PSCo.

(b) NRG VaR was an undiversified VaR. NRG is presented as discontinued operations.

(c) Conducted by e prime, which is a discontinued operation held for sale.

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. 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.

At Dec. 31, 2003, a 10 percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $3.6 million, while a decrease of 10 percent would have resulted in a decrease of $3.9 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of dollars)	***2003***	*2002*	*2001*
Cash provided by operating activities			
Continuing operations	**$1,135**	$1,300	$1,388
Discontinued operations	**243**	415	196
Total	**$1,378**	$1,715	$1,584

Cash provided by operating activities for continuing operations decreased during 2003 compared with 2002 primarily due to decreases in recovery of deferred fuel costs. Cash provided by operating activities for discontinued operations decreased during 2003 compared with 2002 due to the deconsolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. The decrease was partially offset by tax benefits received in connection with the divestiture of NRG in 2003.

Cash provided by operating activities for continuing operations decreased during 2002 compared with 2001 due to lower 2002 utility receivables and unbilled revenues, reflecting collections of higher year-end 2001 amounts. Cash provided by operating activities for discontinued operations 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.

(Millions of dollars)	***2003***	*2002*	*2001*
Cash used in investing activities			
Continuing operations	**$(1,072)**	$(1,056)	$(1,156)
Discontinued operations	**146**	(1,655)	(4,017)
Total	**$ (926)**	$(2,711)	$(5,173)

Cash used in investing activities for continuing operations was approximately the same during 2003 compared with 2002 due to comparable utility construction expenditures. Cash flows for investing activities related to discontinued operations increased during 2003 compared with 2002 due to the deconsolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. NRG had significant construction expenditures during 2002 prior to its financial difficulties.

Cash used in investing activities for continuing operations decreased slightly during 2002 compared with 2001 primarily due to lower utility construction expenditures in 2002. Cash used in investing activities for discontinued operations 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.

(Millions of dollars)	***2003***	*2002*	*2001*
Cash (used in) provided by financing activities			
Continuing operations	**$(367)**	$ 115	$ (435)
Discontinued operations	**–**	1,465	4,148
Total	**$(367)**	$1,580	$3,713

Cash flows for financing activities related to continuing operations decreased during 2003 compared with 2002 due to refinancing activities in 2003 to better align Xcel Energy's capital structure and manage the cost of capital given the improving credit quality of Xcel Energy and its subsidiaries. During 2003, Xcel Energy and its subsidiaries extinguished $1.3 billion of long-term debt and issued approximately $1.7 billion of long-term debt, as shown in the Consolidated Statement of Capitalization. Cash flows for financing activities related to discontinued operations decreased during 2003 compared with 2002 due to the deconsolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. NRG obtained financing in 2002 for its construction expenditures prior to experiencing its financial difficulties.

Cash flow for financing activities related to continuing operations increased during 2002 compared with 2001 primarily due to refinancing activities in 2002, including the redemption of $867 million of short-term debt and the issuance of $1.4 billion of new debt. Cash flow provided by financing activities for discontinued operations 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.

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 discontinued operations, and other capital requirements for the years 2004, 2005 and 2006 are shown in the table below.

(Millions of dollars)	*2004*	*2005*	*2006*
Electric utility	$ 975	$ 975	$1,064
Natural gas utility	115	133	111
Common utility	101	112	106
Total utility	1,191	1,220	1,281
Other nonregulated	30	31	15
Total capital expenditures	1,221	1,251	1,296
Sinking funds and debt maturities	153	224	837
Total capital requirements	$1,374	$1,475	$2,133

The capital expenditure forecast includes new steam generators at the Prairie Island nuclear plant, new combustion turbines in two NSP-Minnesota plants and costs related to a proposed coal-fired generating plant in Colorado. The capital expenditure forecast also includes the early stages of the costs related to the MERP modifications to reduce the emissions of NSP-Minnesota's generating plants located in the Minneapolis-St. Paul metropolitan area. The MERP project is expected to cost approximately $1 billion, with major construction starting in 2005 and finishing in 2009. Xcel Energy expects to recover the costs of the emission-reduction project through customer rate increases beginning in 2006.

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 restructuring requirements, compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements. For more information, see Note 17 to the Consolidated Financial Statements.

Xcel Energy's investment in exempt wholesale generators and foreign utility companies is currently limited to 100 percent of consolidated retained earnings as a result of the PUHCA restrictions. At this time, Xcel Energy has no capacity to make additional investments in exempt wholesale generators and foreign utility companies without authorization from the SEC.

Contractual Obligations and Other Commitments Xcel Energy has contractual obligations and other commercial commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2003. See additional discussion in the Consolidated Statements of Capitalization and Notes 4, 5, 6, 8, 15 and 17 to the Consolidated Financial Statements.

		Payments due by period			
(Thousands of dollars)	*Total*	*Less than 1 year*	*1 to 3 years*	*4 to 5 years*	*After 5 years*
Long-term debt	$ 6,635,158	$ 158,024	$1,058,169	$ 991,058	$4,427,907
Capital lease obligations	106,315	7,365	13,860	12,964	72,126
Operating leases *(a)*	272,211	48,567	95,826	81,772	46,046
NRG bankruptcy settlement	752,000	752,000	–	–	–
Unconditional purchase obligations *(b)*	10,861,257	1,669,769	2,521,209	1,937,336	4,732,943
Other long-term obligations	180,112	39,976	49,654	37,439	53,043
Payments to vendors in process	96,887	96,887	–	–	–
Short-term debt	58,563	58,563	–	–	–
Total contractual cash obligations *(c)*	$18,962,503	$2,831,151	$3,738,718	$3,060,569	$9,332,065

(a) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment, and aircraft leases have these terms. At Dec. 31, 2003, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $142.9 million.

(b) Obligations to purchase fuel for electric generating plants, and electricity and natural gas for resale. Energy costs are largely recoverable from customers in rates. In addition, approximately $2 billion of the obligation is based on prices tied to a commodity index; as such the obligation will change as the commodity index changes.

(c) Xcel Energy also has outstanding authority under contracts and blanket purchase orders to purchase up to $600 million of goods and services through the year 2020, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

In addition, Xcel Energy's board of directors approved the repurchase of 2.5 million shares of common stock to fulfill the requirements of the restricted stock unit exercise in 2004.

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. The ultimate dividend policy will balance:

- projected cash generation from utility operations;
- projected capital investment in the utility businesses;
- reasonable rate of return on shareholder investment; and
- impact on Xcel Energy's capital structure and credit ratings.

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. Xcel Energy had $369 million of retained earnings at Dec. 31, 2003, and expects to declare dividends as scheduled. The cash to pay dividends to Xcel Energy shareholders is primarily derived from dividends received from the utility subsidiaries. The utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory commissions to be paid to the holding company. The limitation is imposed through equity ratio limitations that range from 30 percent to 57 percent. All utility subsidiaries are required under PUHCA to pay dividends only from retained earnings, and some must comply with covenant restrictions under credit agreements for debt and interest coverage ratios.

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 common stock plus surplus divided by the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's capitalization ratio at Dec. 31, 2003, was 83 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy's 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 Xcel Energy 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.

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, are limited under PUHCA in their ability to issue securities. Such registered holding companies and their subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy does not qualify for any of the main exemptive rules, it sought and received financing authority from the SEC under PUHCA for various financing arrangements. Xcel Energy's current financing authority permits it, subject to satisfaction of certain conditions, to issue through June 30, 2005, up to $2.5 billion of common stock and long-term debt and $1.5 billion of short-term debt at the holding-company level. Xcel Energy has issued $2 billion of long-term debt and common stock, including the $400 million credit facility.

Xcel Energy's ability to issue securities under the financing authority is subject to a number of conditions. One of the conditions of the financing authority is that Xcel Energy's consolidated ratio of common equity to total capitalization be at least 30 percent. As of Dec. 31, 2003, the common equity ratio was approximately 43 percent. Additional conditions require that a security to be issued that is rated, be rated investment grade by at least one nationally recognized rating agency. Finally, all outstanding securities (except preferred stock) that are rated must be rated investment grade by at least one nationally recognized rating agency. On Feb. 20, 2004, Xcel Energy's senior unsecured debt was considered investment grade by Standard & Poor's Ratings Services (Standard & Poor's) and Moody's Investors Services, Inc. (Moody's).

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 construction expenditures. Another significant short-term funding need is the dividend payment.

In 2003, Xcel Energy established a money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The money pool allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates. The money pool arrangement does not allow loans from the utility subsidiaries to the holding company. State regulatory commission approval of the arrangement is pending.

As of Feb. 20, 2004, Xcel Energy had the following credit facilities available to meet its liquidity needs:

Company (Millions of dollars)	*Facility*	*Drawn**	*Available*	*Cash*	*Liquidity*	*Maturity*
NSP-Minnesota	$ 275	$ 43	$232	$130	$ 362	May 2004
NSP-Wisconsin	–	–	–	–	–	–
PSCo	350	1	349	171	520	May 2004
SPS	125	40	85	21	106	February 2005 **
Xcel Energy – holding company***	400	89	311	–	311	November 2005
Total	$1,150	$173	$977	$322	$1,299	

** Includes short-term borrowings and letters of credit.*

*** The SPS $100 million facility expired in February 2004 and was replaced with a $125 million unsecured, 364-day credit agreement.*

**** Reflects the $400 million NRG payment made in February 2004.*

Operating cash flow as a source of short-term funding is 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, which are difficult to predict. See further discussion of such factors under Statement of Operations Analysis.

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. 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 dependent in part on credit agency reviews and ratings. The following 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. 20, 2004, 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	A2
NSP-Minnesota	Senior Unsecured Debt	Baa1	BBB-
NSP-Minnesota	Senior Secured Debt	A3	BBB+
NSP-Minnesota	Commercial Paper	P2	A2
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	A2
SPS	Senior Unsecured Debt	Baa1	BBB
SPS	Commercial Paper	P2	A2

Note: Moody's highest credit rating for debt is Aaa1 and lowest investment grade rating is Baa3. Standard & Poor's highest credit rating for debt is AAA+ and lowest investment grade rating is BBB-. Moody's prime ratings for commercial paper range from P1 to P3. NP denotes a nonprime rating. Standard & Poor's ratings for commercial paper range from A1 to A3, B and C. As of Feb. 10, 2004, Moody's had Xcel Energy and its operating utility subsidiaries "under review for possible upgrade." Standard & Poor's had Xcel Energy and its operating utility subsidiaries on "credit watch positive."

In the event of a downgrade of its credit ratings below investment grade, Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy all or a part of its exposures under guarantees outstanding. See a list of guarantees at Note 15 to the Consolidated Financial Statements. Xcel Energy has no explicit rating triggers in its debt agreements.

Registration Statements Xcel Energy's Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2003, 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, 2003, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Xcel Energy and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- 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.
- In April 2001, NSP-Minnesota filed a $600 million, long-term debt shelf registration with the SEC. NSP-Minnesota has approximately $40 million remaining under this registration.
- PSCo has an effective shelf registration statement with the SEC under which $800 million of secured first collateral trust bonds or unsecured senior debt securities were registered. PSCo has approximately $225 million remaining under this registration.

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments through internally generated funds. Xcel Energy plans to renew its credit facilities at NSP-Minnesota, PSCo and SPS during 2004 and may refinance existing long-term debt with lower-rate debt, based on market conditions. See discussion of funding for the NRG settlement payments in the following section.

Impact of Settlement Agreement with NRG

As discussed previously and in Note 4 to the Consolidated Financial Statements, NRG has completed its plan of reorganization through a bankruptcy proceeding, and the terms of a settlement among NRG, Xcel Energy and members of NRG's major creditor constituencies was approved and put into effect.

As part of the reorganization, Xcel Energy completely divested its ownership interest in NRG, which in turn issued new common equity to its creditors. The financial terms of the settlement agreement included a provision that Xcel Energy will pay $752 million to NRG to settle all claims of NRG against Xcel Energy and claims of NRG creditors against Xcel Energy under the NRG plan of reorganization as follows:

- $400 million paid on Feb. 20, 2004, including $112 million to NRG's bank lenders.
- $352 million will be paid on April 30, 2004, unless at such time Xcel Energy has not received tax refunds equal to at least $352 million associated with the loss on its investment in NRG. To the extent such refunds are less than the required payments, the difference between the required payments and those refunds would be due on May 30, 2004.
- In return for such payments, Xcel Energy received, or was granted, voluntary and involuntary releases from NRG and its creditors.

Xcel Energy intends to fund the payments required by the settlement agreement with cash received for tax benefits related to its investment in NRG, cash on hand and available Xcel Energy credit facilities.

Based on current forecasts of taxable income and tax liabilities, Xcel Energy expects to realize approximately $1.1 billion of cash savings from these tax benefits through a refund of taxes paid in prior years and reduced taxes payable in future years. Xcel Energy used $130 million of these tax benefits in 2003 and expects to use $480 million in 2004. The remainder of the tax benefit carry forward is expected to be used over subsequent years.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

Xcel Energy's 2004 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

	2004 Diluted EPS Range
Utility operations	$1.25–$1.33
Holding company financing costs	(0.08)
Seren	(0.03)
Eloigne	0.01
Other nonregulated subsidiaries	0.00–0.02
Xcel Energy Continuing Operations – EPS	$1.15–$1.25

Key assumptions for 2004:

- NRG has no impact on Xcel Energy's financial results in 2004;
- normal weather patterns throughout 2004;
- weather-adjusted retail electric utility sales growth of 2.2 percent;
- weather-adjusted firm retail gas utility sales growth of approximately 2.4 percent;
- successful outcome of the requested capacity rider revenue increase in Colorado;
- 2004 trading and short-term wholesale margins are expected to be slightly less than 2003 margins to reflect more normal market conditions;
- 2004 utility operating and maintenance expense is expected be relatively flat, compared with 2003 levels;
- 2004 depreciation expense is projected to increase by about 2 percent compared with 2003;
- 2004 interest expense is projected to decline by approximately $15 million, compared with 2003 levels;
- an effective tax rate of approximately 31 percent; and
- average common stock and equivalents of approximately 425 million shares in 2004, based on the "If Converted" method for convertible notes.

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, 2003 and 2002, and the related consolidated statements of operations, common stockholders' equity and other comprehensive income and cash flows for the three years ended December 31, 2003. 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 year ended December 31, 2002, or the consolidated statements of operations, stockholder's (deficit)/equity and cash flows for the two years ended December 31, 2002 included in the consolidated financial statements of the Company, which statements reflect total assets of $10.9 billion as of December 31, 2002 and losses from discontinued operations net of tax of $3.5 billion for the year ended December 31, 2002, and income from discontinued operations net of tax of $265 million for the year ended December 31, 2001. 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 paragraph 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 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, 2003 and 2002 and the results of their operations and their cash flows for each of the three years ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

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."

As discussed in Note 18 to the consolidated financial statements, effective January 1, 2003, Xcel Energy Inc. and subsidiaries adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" and as discussed in Note 16, effective October 1, 2003, Derivatives Implementation Group Issue No. C20 "Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) Regarding Contracts with a Price Adjustment Feature."

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 27, 2004

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder's (deficit)/equity (not presented separately herein) present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries at December 31, 2002, and the results of their operations and their cash flows for each of the two 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 consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 and Note 29 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, the Company and certain of its subsidiaries filed 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 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, except as to Notes 29 and 30, which are as of December 3, 2003.

(Thousands of dollars, except per share data)	2003	Year ended Dec. 31 2002	2001
OPERATING REVENUES			
Electric utility	**$5,952,191**	$ 5,435,377	$6,394,737
Natural gas utility	**1,710,272**	1,363,360	2,022,803
Electric trading margin	**17,165**	1,642	69,641
Nonregulated and other	**257,888**	234,749	236,846
Total operating revenues	**7,937,516**	7,035,128	8,724,027
OPERATING EXPENSES			
Electric fuel and purchased power – utility	**2,710,455**	2,199,099	3,171,404
Cost of natural gas sold and transported – utility	**1,208,274**	852,813	1,521,236
Cost of sales – nonregulated and other	**156,626**	132,628	127,557
Other operating and maintenance expenses – utility	**1,580,630**	1,490,027	1,493,015
Other operating and maintenance expenses – nonregulated	**101,723**	110,172	89,726
Depreciation and amortization	**756,000**	771,265	726,795
Taxes (other than income taxes)	**319,522**	318,822	312,840
Special charges (see Note 2)	**19,039**	19,265	62,230
Total operating expenses	**6,852,269**	5,894,091	7,504,803
Operating income	**1,085,247**	1,141,037	1,219,224
Interest and other income, net of nonoperating expenses (see Note 13)	**35,717**	44,677	30,754
INTEREST CHARGES AND FINANCING COSTS			
Interest charges – net of amounts capitalized (includes other financing costs of $32,184, $34,884 and $11,211, respectively)	**429,571**	384,063	327,636
Distributions on redeemable preferred securities of subsidiary trusts	**22,731**	38,344	38,800
Total interest charges and financing costs	**452,302**	422,407	366,436
Income from continuing operations before income taxes	**668,662**	763,307	883,542
Income taxes	**158,642**	235,614	304,342
Income from continuing operations	**510,020**	527,693	579,200
Income (loss) from discontinued operations – net of tax (see Note 3)	**112,372**	(2,745,684)	203,945
Income (loss) before extraordinary items	**622,392**	(2,217,991)	783,145
Extraordinary items – net of tax of $5,747	**–**	–	11,821
Net income (loss)	**622,392**	(2,217,991)	794,966
Dividend requirements on preferred stock	**4,241**	4,241	4,241
Earnings (loss) available to common shareholders	**$ 618,151**	$(2,222,232)	$ 790,725
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (IN THOUSANDS)			
Basic	**398,765**	382,051	342,952
Diluted	**418,912**	384,646	343,742
EARNINGS (LOSS) PER SHARE – BASIC			
Income from continuing operations	**$ 1.27**	$ 1.37	$ 1.69
Discontinued operations (see Note 3)	**0.28**	(7.19)	0.59
Extraordinary items (see Note 14)	**–**	–	0.03
Earnings (loss) per share	**$ 1.55**	$ (5.82)	$ 2.31
EARNINGS (LOSS) PER SHARE – DILUTED			
Income from continuing operations	**$ 1.23**	$ 1.37	$ 1.68
Discontinued operations (see Note 3)	**0.27**	(7.14)	0.59
Extraordinary items (see Note 14)	**–**	–	0.03
Earnings (loss) per share	**$ 1.50**	$ (5.77)	$ 2.30

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	*2003*	*Year ended Dec. 31* *2002*	*2001*
OPERATING ACTIVITIES			
Net (loss) income	**$ 622,392**	$(2,217,991)	$ 794,966
Remove (income) loss from discontinued operations	**(112,372)**	2,745,684	(203,945)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	**786,532**	792,954	767,445
Nuclear fuel amortization	**43,401**	48,675	41,928
Deferred income taxes	**113,985**	148,765	(9,653)
Amortization of investment tax credits	**(12,499)**	(13,272)	(12,867)
Allowance for equity funds used during construction	**(25,338)**	(7,793)	(6,739)
Undistributed equity in earnings of unconsolidated affiliates	**(5,628)**	5,774	(5,275)
Gain on sale of property	**–**	(6,785)	–
Write-downs and losses from investments	**8,856**	15,866	–
Unrealized gain on derivative financial instruments	**(1,954)**	17,779	(6,237)
Extraordinary items – net of tax (see Note 14)	**–**	–	(11,821)
Change in accounts receivable	**(129,971)**	28,155	126,110
Change in inventories	**3,230**	(21,313)	(47,972)
Change in other current assets	**(172,100)**	116,632	402,543
Change in accounts payable	**102,734**	(137,050)	(346,352)
Change in other current liabilities	**(4,070)**	(139,917)	78,524
Change in other noncurrent assets	**(133,364)**	(215,836)	(299,162)
Change in other noncurrent liabilities	**50,798**	139,885	126,735
Operating cash flows provided by discontinued operations	**243,354**	414,899	195,784
Net cash provided by operating activities	**1,377,986**	1,715,111	1,584,012
INVESTING ACTIVITIES			
Utility capital/construction expenditures	**(950,940)**	(908,878)	(1,103,685)
Allowance for equity funds used during construction	**25,338**	7,793	6,739
Investments in external decommissioning fund	**(80,581)**	(57,830)	(54,996)
Nonregulated capital expenditures and asset acquisitions	**(42,287)**	(64,117)	(53,852)
Equity investments, loans, deposits and sales of nonregulated projects	**13,300**	(17,253)	3,316
Restricted cash	**(38,488)**	(23,000)	–
Other investments – net	**1,069**	7,001	46,584
Investing cash flows provided by (used in) discontinued operations	**146,493**	(1,655,042)	(4,016,631)
Net cash used in investing activities	**(926,096)**	(2,711,326)	(5,172,525)
FINANCING ACTIVITIES			
Short-term borrowings – net	**(445,080)**	(867,466)	85,921
Proceeds from issuance of long-term debt	**1,689,317**	1,442,172	307,058
Repayment of long-term debt, including reacquisition premiums	**(1,311,012)**	(32,802)	(437,692)
Proceeds from issuance of common stock	**3,219**	69,488	129,011
Dividends paid	**(303,316)**	(496,375)	(518,894)
Financing cash flows provided by discontinued operations	**–**	1,465,070	4,147,928
Net cash (used in) provided by financing activities	**(366,872)**	1,580,087	3,713,332
Net increase in cash and cash equivalents	**85,018**	583,872	124,819
Net increase (decrease) in cash and cash equivalents – discontinued operations	**3,521**	(241,453)	(98,092)
Cash and cash equivalents at beginning of year	**484,700**	142,281	115,554
Cash and cash equivalents at end of year	**$ 573,239**	$ 484,700	$ 142,281
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	**$ 402,506**	$ 640,628	$ 708,560
Cash paid for income taxes (net of refunds received)	**$ (6,379)**	$ 24,935	$ 327,018

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2003	2002
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 573,239**	$ 484,700
Restricted cash	**37,363**	23,000
Accounts receivable – net of allowance for bad debts: $31,106 and $23,970, respectively	**658,936**	536,476
Accrued unbilled revenues	**368,374**	390,984
Materials and supplies inventories – at average cost	**168,204**	191,041
Fuel inventory – at average cost	**59,706**	67,875
Natural gas inventories – replacement cost in excess of LIFO: $73,197 and $20,502, respectively	**141,315**	114,981
Recoverable purchased natural gas and electric energy costs	**234,859**	63,975
Derivative instruments valuation – at market	**62,537**	6,565
Prepayments and other	**142,596**	118,768
Current assets held for sale and related to discontinued operations	**684,110**	1,738,803
Total current assets	**3,131,239**	3,737,168
Property, plant and equipment, at cost:		
Electric utility plant	**17,320,268**	16,516,790
Natural gas utility plant	**2,484,874**	2,384,051
Nonregulated property and other	**1,553,391**	1,534,449
Construction work in progress: utility amounts of $908,256 and $855,842, respectively	**932,082**	889,902
Total property, plant and equipment	**22,290,615**	21,325,192
Less accumulated depreciation	**(8,703,788)**	(8,084,987)
Nuclear fuel – net of accumulated amortization: $1,101,932 and $1,058,531, respectively	**80,289**	74,139
Net property, plant and equipment	**13,667,116**	13,314,344
Other assets:		
Investments in unconsolidated affiliates	**124,462**	116,094
Nuclear decommissioning fund and other investments	**843,083**	699,077
Regulatory assets	**879,840**	576,876
Derivative instruments valuation – at market	**429,531**	1,494
Prepaid pension asset	**567,227**	448,749
Other	**209,256**	211,738
Noncurrent assets held for sale and related to discontinued operations	**353,626**	10,330,897
Total other assets	**3,407,025**	12,384,925
Total assets	**$20,205,380**	$29,436,437
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	**$159,955**	$558,263
Short-term debt	**58,563**	503,643
Accounts payable	**791,316**	698,170
Taxes accrued	**188,973**	243,183
Dividends payable	**75,866**	75,814
Derivative instruments valuation – at market	**153,467**	11,520
Other	**422,420**	332,618
Current liabilities held for sale and related to discontinued operations	**820,506**	9,925,625
Total current liabilities	**2,671,066**	12,348,836
Deferred credits and other liabilities:		
Deferred income taxes	**2,014,414**	1,894,153
Deferred investment tax credits	**156,555**	169,587
Regulatory liabilities	**1,570,548**	1,328,611
Derivative instruments valuation – at market	**388,743**	10,863
Asset retirement obligations	**1,024,529**	662,411
Customer advances	**212,766**	161,283
Minimum pension liability	**55,528**	106,897
Benefit obligations and other	**313,206**	334,151
Noncurrent liabilities held for sale and related to discontinued operations	**7,471**	1,836,088
Total deferred credits and other liabilities	**5,743,760**	6,504,044
Minority interest in subsidiaries	**281**	296
Commitments and contingencies (see Note 17)		
Capitalization (see Statements of Capitalization):		
Long-term debt	**6,518,853**	5,318,957
Mandatorily redeemable preferred securities of subsidiary trusts	**–**	494,000
Preferred stockholders' equity	**104,980**	105,320
Common stockholders' equity	**5,166,440**	4,664,984
Total liabilities and equity	**$20,205,380**	$29,436,437

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, 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 16)						(28,780)	(28,780)
After-tax net unrealized gains related to derivatives (see Note 16)						63,023	63,023
Unrealized loss – marketable securities						(75)	(75)
Comprehensive income for 2001							772,441
Dividends declared:							
Cumulative preferred stock				(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 from NRG stock offering			241,891				241,891
Repayment of ESOP loan					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 (see Note 16)						(39,475)	(39,475)
Unrealized loss – marketable securities						(457)	(457)
Comprehensive loss for 2002							(2,335,697)
Dividends declared:							
Cumulative preferred stock				(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					18,564		18,564
Balance at Dec. 31, 2002	398,714	996,785	4,038,151	(100,942)	–	(269,010)	4,664,984
Net income				622,392			622,392
Currency translation adjustments						182,829	182,829
Minimum pension liability						9,710	9,710
After-tax net unrealized losses related to derivatives (see Note 16)						(14,005)	(14,005)
Unrealized gain – marketable securities						340	340
Comprehensive income for 2003							801,266
Dividends declared:							
Cumulative preferred stock			(720)	(3,181)			(3,901)
Common stock			(149,521)	(149,606)			(299,127)
Issuances of common stock – net proceeds	251	627	2,591				3,218
Balance at Dec. 31, 2003	**398,965**	**$997,412**	**$3,890,501**	**$ 368,663**	**$ –**	**$ (90,136)**	**$5,166,440**

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2003	2002
LONG-TERM DEBT		
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2004–2006, 3.9%–4.1%	**$ 6,990** *(a)*	$ 9,145 *(a)*
March 1, 2003, 5.875%	–	100,000
April 1, 2003, 6.375%	–	80,000
Dec. 1, 2005, 6.125%	**70,000**	70,000
Aug. 1, 2006, 2.875%	**200,000**	–
Aug. 1, 2010, 4.75%	**175,000**	–
Aug. 28, 2012, 8%	**450,000**	450,000
March 1, 2011, variable rate, 6.265% at Dec. 31, 2002	–	13,700 *(b)*
March 1, 2019, 8.5%	**27,900** *(b)*	27,900 *(b)*
Sept. 1, 2019, 8.5%	**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, 8.5%	**69,000** *(b)*	69,000 *(b)*
Dec. 1, 2004–2008, 4.35%–5%	**11,990** *(a)*	14,090 *(a)*
Guaranty Agreements, Series due Feb. 1, 2003–May 1, 2003, 5.375%–7.4%	–	28,450 *(b)*
Senior Notes due Aug. 1, 2009, 6.875%	**250,000**	250,000
Retail Notes due July 1, 2042, 8%	**185,000**	185,000
Other	**399**	427
Unamortized discount – net	**(8,721)**	(8,931)
Total	**1,937,558**	1,788,781
Less redeemable bonds classified as current (see Note 6)	–	13,700
Less current maturities	**4,502**	212,762
Total NSP-Minnesota long-term debt	**$1,933,056**	$1,562,319
PSCo Debt		
First Mortgage Bonds, Series due:		
April 15, 2003, 6%	**$ –**	$ 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)*
Oct. 1, 2008, 4.375%	**300,000**	–
June 1, 2012, 5.5%	**50,000** *(b)*	50,000 *(b)*
Oct. 1, 2012, 7.875%	**600,000**	600,000
March 1, 2013, 4.875%	**250,000**	–
April 1, 2014, 5.5%	**275,000**	–
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
Jan. 1, 2024, 7.25%	**110,000**	110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	**200,000**	200,000
Secured Medium-Term Notes, due Feb. 2, 2004–March 5, 2007, 6.9%–7.11%	**145,000**	175,000
Unamortized discount	**(6,835)**	(4,612)
Capital lease obligations, 11.2% due in installments through May 31, 2025	**47,650**	49,747
Total	**2,458,565**	2,064,225
Less current maturities	**147,131**	282,097
Total PSCo long-term debt	**$2,311,434**	$1,782,128

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2003	2002
LONG-TERM DEBT – CONTINUED		
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
Unsecured Senior C Notes, due Oct. 1, 2033, 6%	**100,000**	–
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	**44,500**	44,500
July 1, 2016, 1.25% at Dec. 31, 2003, and 1.6% at Dec. 31, 2002	**25,000**	25,000
Sept. 1, 2016, 5.75%	**57,300**	57,300
Unamortized discount	**(1,653)**	(1,138)
Total SPS long-term debt	**$ 825,147**	$ 725,662
NSP-Wisconsin Debt		
First Mortgage Bonds Series due:		
Oct. 1, 2003, 5.75%	**$ –**	$ 40,000
Oct. 1, 2018, 5.25%	**150,000**	–
March 1, 2023, 7.25%	**–**	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%	**895**	930
Senior Notes – due, Oct. 1, 2008, 7.64%	**80,000**	80,000
Unamortized discount	**(1,051)**	(1,388)
Total	**313,444**	313,142
Less current maturities	**34**	40,034
Total NSP-Wisconsin long-term debt	**$ 313,410**	$ 273,108
Other Subsidiaries Debt		
First Mortgage Bonds – Cheyenne:		
Series due April 1, 2003–Jan. 1, 2024, 7.5%–7.875%	**$ 8,000**	$ 12,000
Industrial Development Revenue Bonds, due Sept. 1, 2021–March 1, 2027, variable rate, 1.3% and 1.7% at Dec. 31, 2003 and 2002	**17,000**	17,000
Various Eloigne Co. Affordable Housing Project Notes, due 2004–2026, 0.3%–9.91%	**39,139**	41,353
Other	**12,140**	94,894
Total	**76,279**	165,247
Less current maturities	**8,288**	9,670
Total other subsidiaries long-term debt	**$ 67,991**	$ 155,577
Xcel Energy Inc. Debt		
Unsecured Senior Notes, Series due:		
July 1, 2008, 3.4%	**$ 195,000**	$ –
Dec. 1, 2010, 7%	**600,000**	600,000
Convertible notes, Series due:		
Nov. 21, 2007, 7.5%	**230,000**	230,000
Nov. 21, 2008, 7.5%	**57,500**	–
Fair value hedge, carrying value adjustment	**(6,298)**	–
Unamortized discount	**(8,387)**	(9,837)
Total Xcel Energy Inc. debt	**$1,067,815**	$ 820,163
Total long-term debt from continuing operations	**$6,518,853**	$5,318,957
Long-Term Debt from Discontinued Operations		
Viking Gas Transmission Co. Senior Notes, Series due:		
Oct. 31, 2008–Sept. 30, 2014, 6.65%–8.04%	**$ –**	$ 40,421
Black Mountain Gas notes, due June 1, 2004–May 1, 2005, 6%	**–**	3,000
NRG long-term debt:		
Remarketable or Redeemable Securities, due March 15, 2005, 7.97%	**–**	257,552
NRG Energy, Inc. Senior Notes, Series due:		
Feb. 1, 2006, 7.625%	**–**	125,000
June 15, 2007, 7.5%	**–**	250,000
June 1, 2009, 7.5%	**–**	300,000
Nov. 1, 2013, 8%	**–**	240,000
Sept. 15, 2010, 8.25%	**–**	350,000
July 15, 2006, 6.75%	**–**	340,000
April 1, 2011, 7.75%	**–**	350,000
April 1, 2031, 8.625%	**–**	500,000
May 16, 2006, 6.5%	**–**	285,728

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2003	2002
LONG-TERM DEBT – CONTINUED		
NRG Finance Co. LLC, due May 9, 2006, various rates	–	1,081,000
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	–	126,500
June 15, 2015, 8.842%	–	130,000
Dec. 15, 2024, 9.292%	–	300,000
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	–	450,750
Sept. 15, 2024, 9.479%	–	300,000
MidAtlantic – various, due Oct. 1, 2005, 4.625%	–	409,201
Flinders Power Finance Pty, due September 2012, various rates of 6.14%–6.49% at Dec. 31, 2002	–	99,175
Brazos Valley, due June 30, 2008, 6.75%	–	194,362
Camas Power Boiler, due June 30, 2007, and Aug. 1, 2007, 3.65% and 3.38%	–	17,861
Sterling Luxembourg #3 Loan, due June 30, 2019, variable rate	–	360,122
Hsin Yu Energy Development, due November 2006–April 2012, 4%–6.475%	–	85,607
LSP Batesville, due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	–	314,300
LSP Kendall Energy, due Sept. 1, 2005, 2.65%	–	495,754
McClain, due Dec. 31, 2005, 6.75%	–	157,288
NEO, due 2005–2008, 9.35%	–	7,658
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	–	133,099
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
Audrain Capital Lease Obligation, due Dec. 31, 2023, 10%	–	239,930
Saale Energie GmbH Schkopau Capital Lease, due May 2021, various rates	–	333,926
Various debt, due 2003–2007, 0.0%–20.8%	–	92,573
Other	–	677
Total	–	8,875,018
Less current maturities	–	7,643,654
Total long-term debt from discontinued operations	$ –	$1,231,364
Mandatorily Redeemable Preferred Securities of Subsidiary Trusts holding as their sole asset the junior subordinated deferrable debentures of the following (see Note 8):		
NSP-Minnesota, due 2037, 7.875%	$ –	$ 200,000
PSCo, due 2038, 7.6%	–	194,000
SPS, due 2036, 7.85%	–	100,000
Total mandatorily redeemable preferred securities of subsidiary trusts	$ –	$ 494,000
Cumulative Preferred Stock – authorized 7,000,000 shares of $100 par value; outstanding shares: 2003: 1,049,800; 2002: 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
$4.56 series, 150,000 shares	**15,000**	15,000
Total	**104,980**	104,980
Capital in excess of par value on preferred stock	–	340
Total preferred stockholders' equity	**$ 104,980**	$ 105,320
Common Stockholders' Equity		
Common stock – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2003: 398,964,724; 2002: 398,714,039	**$ 997,412**	$ 996,785
Capital in excess of par value on common stock	**3,890,501**	4,038,151
Retained earnings (deficit)	**368,663**	(100,942)
Accumulated other comprehensive income (loss)	**(90,136)**	(269,010)
Total common stockholders' equity	**$5,166,440**	$4,664,984

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business and System of Accounts Xcel Energy's 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 respects.

Principles of Consolidation Xcel Energy directly owns five utility subsidiaries that serve electric and natural gas customers in 11 states. These 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) and Cheyenne Light, Fuel and Power Co. (Cheyenne). Their service territories include portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy's regulated subsidiaries also included WestGas Interstate Inc. (WGI), an interstate natural gas pipeline company. Also, until 2003, Xcel Energy's regulated businesses included Viking Gas Transmission Co. (Viking), which was sold in January 2003, and Black Mountain Gas Co. (BMG), which was sold in October 2003. See Note 3 to the Consolidated Financial Statements for more information on the discontinued operations of Viking and BMG. In January 2004, Xcel Energy reached an agreement to sell Cheyenne, pending regulatory approval.

Xcel Energy's nonregulated businesses in continuing operations include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), Planergy International, Inc. (energy management solutions) and Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits). In December 2003, Xcel Energy's board of directors approved management's plan to exit the businesses conducted by the nonregulated subsidiaries Xcel Energy International Inc. (an international independent power producer) and e prime inc. (a natural gas marketing and trading company). Both of these businesses are presented as a component of discontinued operations, as discussed in Note 3 to the Consolidated Financial Statements.

Xcel Energy also divested its ownership interest in NRG Energy, Inc. (NRG), an independent power producer, in 2003. Xcel Energy owned 82 percent of NRG at the beginning of 2001. In March 2001, 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, resulting in 100-percent ownership interest at Dec. 31, 2002. On May 14, 2003, NRG and certain of its affiliates filed voluntary petitions in the U.S. Bankruptcy Court for the Southern District of New York for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. On Dec. 5, 2003, NRG completed its reorganization and emerged from bankruptcy. As a result, Xcel Energy divested its ownership interest in NRG. At Dec. 31, 2003, Xcel Energy reports NRG's financial activity as a component of discontinued operations. See Note 3 to the Consolidated Financial Statements.

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, a proportionate share of pretax income is recorded as equity earnings from investments in affiliates. The portion of earnings from international investments is recorded after subtracting foreign income taxes, if applicable. In the consolidation process, all significant intercompany transactions and balances are eliminated. Xcel Energy has investments in several plants and transmission facilities jointly owned with other utilities. These projects are accounted for on a proportionate consolidation basis, consistent with industry practice. See Note 9 to the Consolidated Financial Statements.

Revenue Recognition Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is determined.

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. A summary of significant rate-adjustment mechanisms follows:

- PSCo's electric rates in Colorado permitted recovery of 100 percent of prudently incurred 2003 electric fuel and purchased energy expense. In 2002 and 2001, PSCo's electric rates in Colorado were adjusted under an incentive cost-adjustment mechanism, which resulted in the sharing of cost increases and decreases with customers and sharing of trading margins, as discussed later.
- NSP-Minnesota's rates include a cost-of-fuel-and-energy and a 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-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. In Wisconsin, requests can be made for 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 provides for an annual earnings test. NSP-Minnesota and PSCo operate under various service standards, which could require customer refunds if certain criteria are not met. NSP-Minnesota 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 provide electric fuel and purchased energy cost recovery. In New Mexico, SPS also has a monthly fuel and purchased power cost-recovery factor.
- NSP-Minnesota, NSP-Wisconsin, PSCo and SPS sell firm power and energy in wholesale markets, which are regulated by the FERC. These rates include monthly wholesale fuel cost-recovery mechanisms.

Trading Operations All applicable gains and losses related to energy trading activities, whether or not settled physically, are shown net in the statement of operations. Electric trading costs, including such gains and losses, are reported as an offset to Electric Trading Revenues to present Electric Trading Margin on a net basis.

Xcel Energy's electric trading operations are conducted by NSP-Minnesota and PSCo. Pursuant to a joint operating agreement (JOA), approved by the FERC, some of the electric trading activity 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 mark-to-market accounting. In addition, trading results include the impacts of any margin-sharing mechanisms. In 2003, Xcel Energy's board of directors designated e prime as held for sale. e prime had conducted natural gas commodity trading activities. Consequently, e prime financial results are presented as discontinued operations. For more information, see Notes 3, 15 and 16 to the Consolidated Financial Statements.

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. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps. For further discussion of Xcel Energy's risk management and derivative activities, see Notes 15 and 16 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. Beginning in 2003, removal costs related to asset retirement obligations that are not legal obligations are reflected in regulatory liabilities. 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. Property, plant and equipment also includes costs associated with the engineering design of future generating stations and other property held for future use.

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 3.0, 3.4 and 3.1 for the years ended Dec. 31, 2003, 2002 and 2001, respectively.

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 debt capital for all Xcel Energy entities (as AFDC for utility companies) was approximately $20 million in 2003, $18 million in 2002 and $29 million in 2001. AFDC recorded for equity capital for all Xcel Energy entities was $25 million in 2003, $8 million in 2002 and $7 million in 2001.

Decommissioning Xcel Energy accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The 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. The fair value of external nuclear decommissioning fund investments are estimated based on quoted market prices for those or similar investments. Unrealized gains or losses are deferred as regulatory assets or liabilities. In 2003, NSP-Minnesota adopted Statement of Financial Accounting Standard (SFAS) No. 143, which changed the accounting methodology for nuclear decommissioning costs. For more information on nuclear decommissioning and the impacts of adopting SFAS No. 143, see Note 18 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 Environmental costs are recorded when it is probable Xcel Energy is liable for the costs and the liability can reasonably be estimated. Costs may be deferred as a regulatory asset based on an expectation that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and as remediation proceeds. If several designated responsible parties exist, only Xcel Energy's expected share of the cost is estimated and recorded. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for these estimated removal costs. However, as discussed further in Note 18 to the Consolidated Financial Statements, removal costs recovered in rates were reclassified to Regulatory Liabilities beginning in 2002.

Income Taxes Xcel Energy 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. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries were included in some, but not all, of these combined returns in 2002 and will be included in these returns in 2003. NRG will not be consolidated or combined in any of Xcel Energy's income tax returns after 2003.

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, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 19 to the Consolidated Financial Statements. See a discussion of the income tax policy for international operations in Note 10 to the Consolidated Financial Statements.

Foreign Currency Translation Xcel Energy's foreign operations, which are limited to Xcel Energy International and NRG before divestiture, 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. Revenue, expense and cash flows are translated at weighted-average exchange rates for the period. Xcel Energy accumulates the resulting currency translation adjustments and reports them as a component of Other Comprehensive Income in Common Stockholders' Equity.

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

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

Restricted cash in 2003 consists primarily of funds received from NRG to be used to collateralize in full existing agreements of Xcel Energy to indemnify NRG, which continued after the divestiture of NRG. Restricted cash in 2002 consists primarily of cash collateral for letters of credit and funds held in trust accounts to satisfy the requirements of certain debt agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Inventory All inventory is recorded at average cost, with the exception of natural gas in underground storage at PSCo and Cheyenne, 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:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 19 to the Consolidated Financial Statements.

Stock-Based Employee Compensation Xcel Energy has several stock-based compensation plans. Those plans are accounted for using the intrinsic-value method. Compensation expense is not recorded for stock options because there is no difference between the market price and the purchase price at grant date. Compensation expense is recorded for restricted stock and stock units 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 11 to the Consolidated Financial Statements.

Intangible Assets During 2002, Xcel Energy adopted SFAS No. 142 – "Goodwill and Other Intangible Assets" regarding the accounting for intangible assets and goodwill. Intangible assets with finite lives are amortized over their economic useful lives and periodically reviewed for impairment. Beginning in 2002, goodwill is no longer being amortized, but is 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's goodwill consisted primarily of project-related goodwill at Utility Engineering for 2003 and 2002. During 2003, impairment testing resulted in a $4.8 million write-down in this goodwill.

Intangible assets with finite lives continue to be amortized, and the aggregate amortization expense recognized in both years ended Dec. 31, 2003 and 2002, were $0.3 million. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $0.2 million. Intangible assets consisted of the following:

	Dec. 31, 2003		*Dec. 31, 2002*	
(Millions of dollars)	*Gross Carrying Amount*	*Accumulated Amortization*	*Gross Carrying Amount*	*Accumulated Amortization*
Not amortized:				
Goodwill	**$3.5**	**$0.6**	$8.3	$0.6
Amortized:				
Service contracts	**$ –**	**$ –**	$5.2	$0.8
Trademarks	**$5.1**	**$0.7**	$5.1	$0.6
Prior service costs	**$5.8**	**$ –**	$6.9	$ –
Other (primarily franchises)	**$2.3**	**$0.6**	$2.0	$0.5

The pro forma impact of implementing SFAS No. 142 at Jan. 1, 2001, on the net income and earnings per share for the year ended Dec. 31, 2001, was not material in relation to the amounts previously reported.

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. See Note 3 to the Consolidated Financial Statements for discussion of impairment charges resulting from the application of SFAS No. 144 to NRG's and Xcel Energy International's discontinued operations.

Deferred Financing Costs Other assets also included deferred financing costs, net of amortization, of approximately $49 million at Dec. 31, 2003. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

2004 Changes in Consolidation Policy 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, consolidation has been required only for subsidiaries in which an enterprise has a majority voting interest. Under FIN No. 46, an enterprise's consolidated financial statements will include the consolidation of variable-interest entities in which the enterprise has a controlling financial interest. As a result, Xcel Energy expects that it will be required to consolidate all or a portion of its affordable housing investments made through Eloigne, which currently are accounted for under the equity method. The Xcel Energy utility subsidiaries are party to purchased power agreements, and based on the current guidance, these contracts are not expected to be considered variable interest arrangements under the provisions of FIN No. 46. However, Xcel Energy is still evaluating the issue. Additionally, Xcel Energy is evaluating other arrangements based on criteria in FIN No. 46, and it is likely that some arrangements will require consolidation.

As of Dec. 31, 2003, the assets of the affordable housing investments were approximately $142 million and long-term liabilities were approximately $78 million. Currently, investments of $56 million are reflected as a component of investments in unconsolidated affiliates in the Consolidated Balance Sheet for Dec. 31, 2003. 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 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. Xcel Energy plans to adopt FIN No. 46 in the first quarter of 2004. The impact of consolidating these entities is not expected to have a material impact on net income.

Reclassifications Certain items in the statements of operations and balance sheets have been reclassified from prior period presentation to conform to the 2003 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily related to organizational changes, such as the divestiture of NRG, and the reclassification of asset retirement obligations from Accumulated Depreciation to a liability account.

2. SPECIAL CHARGES

Special charges included in Operating Expenses for the years ended Dec. 31, 2003, 2002 and 2001, include the following:

(Millions of dollars)	***2003***	*2002*	*2001*
Regulated utility special charges:			
Regulatory recovery adjustment (SPS) (see Note 14)	**$ –**	$ 5	$ –
Restaffing (utility and service companies)	**–**	9	39
Post-employment benefits (PSCo)	**–**	–	23
Total regulated utility special charges	**–**	14	62
Other nonregulated special charges:			
Holding company NRG restructuring charges	**12**	5	–
TRANSLink Transmission Co.	**7**	–	–
Total nonregulated special charges	**19**	5	–
Total special charges	**$19**	$19	$62

2003 TRANSLink Transmission Co., LLC In 2003, Xcel Energy recorded a $7 million pretax charge in connection with the suspension of the activities related to the formation of TRANSLink Transmission Co., LLC (TRANSLink). The charge was recorded as a reserve against loans made by Xcel Energy Transco Inc., a subsidiary of Xcel Energy, to TRANSLink Development Company, LLC, an interim start-up company. TRANSLink was a for-profit independent transmission-only company proposed to be formed by Xcel Energy and several other utilities to integrate the operations of their electric transmission systems into a single system. The formation activity was suspended due to continued market and regulatory uncertainty.

2003 and 2002 Holding Company NRG Restructuring Charges In 2003 and 2002, the Xcel Energy holding company incurred approximately $12 million and $5 million, respectively, for charges related to NRG's financial restructuring. Costs in 2003 included approximately $32 million of financial advisor fees, legal costs and consulting costs related to the NRG bankruptcy transaction. These charges were partially offset by a $20 million pension curtailment gain related to the termination of NRG employees from Xcel Energy's pension plan, as discussed in Note 12 to the Consolidated Financial Statements.

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 industry 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 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 Postemployment 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.

Accrued Special Charges The following table summarizes activity related to accrued special charges in 2003, 2002 and 2001:

(Millions of dollars)	*Utility Severance* *
Balance, Dec. 31, 2000	$48
2001 accruals recorded – restaffing	39
Cash payments made in 2001	(50)
Balance, Dec. 31, 2001	37
Adjustments/revisions to prior year accruals	9
Cash payments made in 2002	(33)
Balance, Dec. 31, 2002	13
Cash payments made in 2003	(10)
Balance, Dec. 31, 2003	**$ 3**

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

3. DISCONTINUED OPERATIONS

Pursuant to the requirements of SFAS No. 144, Xcel Energy classified and accounted for certain nonregulated assets as held for sale at Dec. 31, 2003 and 2002. SFAS No. 144 requires that assets held for sale are valued on an asset-by-asset basis at the lower of the carrying amount or fair value less costs to sell. In applying those provisions, management considered cash flow analyses, bids and offers related to those assets and businesses. As a result, Xcel Energy recorded estimated after-tax losses on disposal of nonregulated assets held for sale, as discussed below, of $59 million for the year ended Dec. 31, 2003. In accordance with the provisions of SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

Due to NRG's emergence from bankruptcy in December 2003 and Xcel Energy's corresponding divestiture of its ownership interest in NRG, NRG is now reflected as a discontinued operation at Dec. 31, 2003. Two regulated businesses also were sold during 2003 and have no assets or liabilities remaining at Dec. 31, 2003. Results of operations for these divested businesses, and the results of businesses held for sale, are reported for all periods presented on a net basis as discontinued operations. In addition, the assets and liabilities of the businesses divested in 2003 have been reclassified to corresponding Assets and Liabilities Held for Sale and Related to Discontinued Operations at Dec. 31, 2002, in the accompanying Balance Sheet. The remaining assets and liabilities of businesses still held for sale at Dec. 31, 2003, have been reclassified to the same corresponding amounts for reporting at Dec. 31, 2003 and 2002.

Regulated Natural Gas Utility Segment

During 2003, Xcel Energy completed the sale of two subsidiaries in its regulated natural gas utility segment: Viking, including its interest in Guardian Pipeline, LLC; and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded for the natural gas utility segment, primarily related to the sale of Viking.

NRG Segment

Change in Accounting for NRG in 2003 Prior to NRG's bankruptcy filing in May 2003, Xcel Energy accounted for NRG as a consolidated subsidiary. However, as a result of NRG's bankruptcy filing, Xcel Energy no longer had the ability to control the operations of NRG. Accordingly, effective as of the bankruptcy filing date, Xcel Energy ceased the consolidation of NRG and began accounting for its investment in NRG using the equity method in accordance with Accounting Principles Board Opinion No. 18 – "The Equity Method of Accounting for Investments in Common Stock." After changing to the equity method, Xcel Energy was limited in the amount of NRG's losses subsequent to the bankruptcy date that it was required to record. In accordance with these limitations under the equity method, Xcel Energy stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provide for loss recognition by Xcel Energy until its investment in NRG is written off to zero, with further loss recognition to continue if its financial commitments to NRG exist beyond amounts already invested.

Prior to NRG entering bankruptcy, Xcel Energy recorded more losses than the limitations provide for as of June 30, 2003. Upon Xcel Energy's divestiture of its interest in NRG in December 2003, the NRG losses recorded in excess of Xcel Energy's investment in and financial commitment to NRG were reversed. This resulted in an adjustment of the total NRG losses recorded for the year 2003 to $251 million. Xcel Energy's share of NRG's results for all 2003 periods is reported in a single line item, Equity in Losses of NRG, as a component of discontinued operations. NRG's 2003 results do reflect some effects of asset impairments and restructuring costs, as discussed below. Xcel Energy's share of NRG results for 2002 was a loss of $3.4 billion, due primarily to asset impairments and other charges recorded in the third and fourth quarters of 2002 related to NRG's financial restructuring.

NRG Asset Impairments In 2002, NRG 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 in 2002. NRG completed an analysis of the recoverability of the asset-carrying values of its projects each period, factoring in the probability weighting of different courses of action available to NRG, given its financial position and liquidity constraints at the time of each analysis. 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 2003 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.

NRG's continuing operations incurred $3.5 billion of asset impairments and estimated disposal losses related to projects and equity investments, respectively, with lower expected cash flows or fair values. These charges recorded by NRG in the third and fourth quarters of 2002 included write-downs of $2.3 billion and $983 million for projects in development and operating projects, respectively, and $196 million for impairment charges and disposal losses related to equity investments.

Approximately $2.5 billion of these NRG impairment charges in 2002 related to NRG assets considered held for use under SFAS No. 144 as of Dec. 31, 2002. For fair values determined by similar asset prices, the fair value represented NRG's estimate of recoverability at that time, if the project assets were to be sold. For fair values determined by estimated market price, the fair value represented a market bid or appraisal received by NRG that NRG believed was best reflective of fair value at that time. 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 reflected project-specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operation given assumed market conditions at that time.

NRG continued to incur asset impairments and related charges in 2003. Prior to its bankruptcy filing in May 2003, NRG recorded more than $500 million in impairment and related charges resulting from planned disposals of an international project and several projects in the United States, and to regulatory developments and changing circumstances throughout the second quarter that adversely affected NRG's ability to recover the carrying value of certain merchant generation units in the Northeastern United States.

Nonregulated Subsidiaries – All Other Segment

Xcel Energy International and e prime In December 2003, the board of directors of Xcel Energy approved management's plan to exit the businesses conducted by its nonregulated subsidiaries Xcel Energy International and e prime. Xcel Energy is in the process of marketing the remaining assets and operations of these businesses to prospective buyers and expects to exit the businesses during 2004.

Results of discontinued nonregulated operations in 2003, other than NRG, include an after-tax loss expected on the disposal of all Xcel Energy International assets of $59 million, based on the estimated fair value of such assets. The fair value represents a market bid or appraisal received that is believed to best reflect the assets' fair value at Dec. 31, 2003. Xcel Energy's remaining investment in Xcel Energy International at Dec. 31, 2003, was approximately $39 million. Losses from discontinued nonregulated operations in 2003 also include a charge of $16 million for costs of settling a Commodity Futures Trading Commission trading investigation of e prime.

Results of discontinued nonregulated operations in 2002 were reduced by impairment losses recorded by Xcel Energy International for certain Argentina assets. In 2002, Xcel Energy International 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 Energy International's investment. The project was written down to estimated fair value, based on an appraisal received that is believed to best reflect the assets' fair value at Dec. 31, 2002. The write-down for this Argentina facility was approximately $13 million.

Results of discontinued nonregulated operations in 2002 also were reduced by a loss on disposal of Xcel Energy International's remaining investment in Yorkshire Power Group Limited.

Tax Benefits Related to Investment in NRG With NRG's emergence from bankruptcy in December 2003, Xcel Energy has divested its ownership interest in NRG and plans to take a tax deduction in 2003. These benefits are reported as discontinued operations. During 2002, Xcel Energy recognized tax benefits of $706 million. This benefit was based on the estimated tax basis of Xcel Energy's cash and stock investments already made in NRG, and their deductibility for federal income tax purposes.

Based on the results of a 2003 study, Xcel Energy recorded $105 million of additional tax benefits in 2003, reflecting an updated estimate of the tax basis of Xcel Energy's investments in NRG and state tax deductibility. Upon NRG's emergence from bankruptcy in December 2003, an additional $288 million of tax benefit was recorded to reflect the deductibility of the settlement payment of $752 million, uncollectible receivables from NRG, other state tax benefits and further adjustments to the estimated tax basis in NRG. Another $11 million of state tax benefits were accrued earlier in 2003 based on projected impacts.

Summarized Financial Results of Discontinued Operations

(Thousands of dollars)	*Natural Gas Utility Segment*	*NRG Segment*	*All Other Segment*	*Total*
2003				
Operating revenue	**$ 9,292**	**$ –**	**$174,224**	**$183,516**
Operating and other expenses	**7,980**	**–**	**177,487**	**185,467**
Special charges and impairments	**–**	**(1,664)**	**58,700**	**57,036**
Equity in NRG losses	**–**	**253,043**	**–**	**253,043**
Pretax income (loss) from operations of discontinued components	**1,312**	**(251,379)**	**(61,963)**	**(312,030)**
Income tax expense (benefit)	**354**	**–**	**(401,464)**	**(401,110)**
Income (loss) from operations of discontinued components	**958**	**(251,379)**	**339,501**	**89,080**
Estimated pretax gain on disposal of discontinued components	**40,072**	**–**	**–**	**40,072**
Income tax expense	**16,780**	**–**	**–**	**16,780**
Gain on disposal of discontinued components	**23,292**	**–**	**–**	**23,292**
Net income (loss) from discontinued operations	**$24,250**	**$(251,379)**	**$339,501**	**$112,372**
2002				
Operating revenue and equity in project income	$36,266	$ 3,010,557	$169,994	$ 3,216,817
Operating and other expenses	18,822	3,173,598	161,413	3,353,833
Special charges and impairments (including net disposal losses)	–	3,459,406	26,962	3,486,368
Pretax income (loss) from operations of discontinued components	17,444	(3,622,447)	(18,381)	(3,623,384)
Income tax expense (benefit)	7,004	(172,517)	(706,381)	(871,894)
Income (loss) from operations of discontinued components	10,440	(3,449,930)	688,000	(2,751,490)
Estimated pretax gain on disposal of discontinued components	–	2,814	–	2,814
Income tax benefit	–	(2,992)	–	(2,992)
Gain on disposal of discontinued components	–	5,806	–	5,806
Net income (loss) from discontinued operations	$10,440	$(3,444,124)	$688,000	$(2,745,684)
2001				
Operating revenue and equity in project income	$31,889	$ 3,013,545	$154,113	$ 3,199,547
Operating and other expenses	22,392	2,784,978	156,790	2,964,160
Pretax income (loss) from operations of discontinued components	9,497	228,567	(2,677)	235,387
Income tax expense (benefit)	3,490	33,477	(5,525)	31,442
Net income from discontinued operations	$ 6,007	$ 195,090	$ 2,848	$ 203,945

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

(Thousands of dollars)	*2003*	*2002*
Cash	**$35,039**	$ 440,484
Trade receivables – net	**42,759**	452,804
Derivative instruments valuation – at market	**2,957**	85,436
Deferred income tax benefits	**580,626**	–
Other current assets	**22,729**	760,079
Current assets held for sale	**684,110**	1,738,803
Property, plant and equipment – net	**27,983**	7,248,589
Derivative instruments valuation – at market	**102**	179,534
Deferred income tax benefits	**314,670**	706,000
Other noncurrent assets	**10,871**	2,196,774
Noncurrent assets held for sale	**353,626**	10,330,897
Current portion of long-term debt	**–**	7,643,654
Accounts payable – trade	**51,076**	756,732
NRG settlement payments	**752,000**	–
Derivative instruments valuation – at market	**3,372**	27,247
Other current liabilities	**14,058**	1,497,992
Current liabilities held for sale	**820,506**	9,925,625
Long-term debt	**–**	1,231,364
Deferred income tax	**800**	225,154
Derivative instruments valuation – at market	**77**	104,218
Minority interest	**5,363**	34,466
Other noncurrent liabilities	**1,231**	240,886
Noncurrent liabilities held for sale	**$ 7,471**	$1,836,088

4. NRG RESTRUCTURING, BANKRUPTCY AND REORGANIZATION

In December 2001, 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 exchange 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.

Xcel Energy's reacquisition of all of the 26 percent of NRG shares not then owned by Xcel Energy 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 of directors. 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 continued financial difficulties at NRG, resulting primarily from lower prices for power and declining credit ratings, culminated in NRG and certain of its affiliates filing, on May 14, 2003, voluntary petitions in the U.S. Bankruptcy Court for the Southern District of New York for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. NRG's filing included its plan of reorganization and the terms of the overall settlement among NRG, Xcel Energy and members of NRG's major creditor constituencies that provided for payments by Xcel Energy to NRG and its creditors of $752 million. NRG's creditors and the bankruptcy court approved the plan of reorganization, and on Dec. 5, 2003, NRG completed reorganization and emerged from bankruptcy. As part of the reorganization, Xcel Energy completely divested its ownership interest in NRG, which in turn issued new common equity to its creditors. The other principal terms of the overall settlement include the following:

- Xcel Energy will pay $752 million to NRG to settle all claims of NRG against Xcel Energy and claims of NRG creditors against Xcel Energy under the NRG plan of reorganization:
  - $400 million paid on Feb. 20, 2004, including $112 million to NRG's bank lenders.
  - $352 million will be paid on April 30, 2004, unless at such time Xcel Energy has not received tax refunds equal to at least $352 million associated with the loss on its investment in NRG. To the extent such refunds are less than the required payments, the difference between the required payments and those refunds would be due on May 30, 2004.
  - In return for such payments, Xcel Energy received, or was granted, voluntary and involuntary releases from NRG and its creditors.
- Xcel Energy's exposure on any guarantees, indemnities or other credit-support obligations incurred by Xcel Energy for the benefit of NRG or any NRG subsidiary was terminated, or other arrangements satisfactory to Xcel Energy and NRG were made, such that Xcel Energy has no further exposure, and any cash collateral posted by Xcel Energy has been returned.
- As part of the settlement, any intercompany claims of Xcel Energy against NRG or any subsidiary arising from the provision of goods or services or the honoring of any guarantee were paid in full and in cash in the ordinary course, except that the agreed amount of certain intercompany claims arising or accrued as of Jan. 31, 2003 (approximately $50 million), were reduced to $10 million. The $10 million agreed amount has been satisfied with an unsecured promissory note of NRG in the principal amount of $10 million with a maturity of 30 months and an annual interest rate of 3 percent.
- NRG and its subsidiaries will not be reconsolidated with Xcel Energy or any of its other affiliates for tax purposes at any time after their March 2001 federal tax de-consolidation (except to the extent required by state or local tax law) or treated as a party to or otherwise entitled to the benefits of any existing tax-sharing agreement with Xcel Energy. However, NRG and certain subsidiaries would continue to be treated substantially as they were under the December 2000 tax allocation agreement to the extent they remain part of a consolidated or combined state tax group that includes Xcel Energy, and with respect to any adjustments to pre-March 2001 federal tax periods. Under the settlement agreement, NRG will not be entitled to any tax benefits associated with the tax loss Xcel Energy expects to recognize as a result of the cancellation of its stock in NRG on the effective date of the NRG plan of reorganization.

5. SHORT-TERM BORROWINGS

Notes Payable At Dec. 31, 2003 and 2002, Xcel Energy and its continuing subsidiaries had approximately $59 million and $504 million, respectively, in notes payable to banks. The weighted average interest rate at Dec. 31, 2003, was 3.97 percent.

Credit Facilities As of Dec. 31, 2003, Xcel Energy had the following credit facilities available:

Credit Line

	Maturity	*Term*	*Credit Line*	*Available*
Xcel Energy	November 2005	5 years	$400 million	$381 million
NSP-Minnesota	May 2004	364 days	$275 million	$175 million
PSCo	May 2004	364 days	$350 million	$349 million
SPS	February 2004	364 days	$100 million	$ 97 million
Other subsidiaries	Various	Various	$ 65 million	$ 65 million

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit, and, depending on credit ratings, support for commercial paper borrowings. Of the notes payable to banks, $58 million was drawn on the lines of credit at Dec. 31, 2003, and reduced the amounts available under these credit lines. Also, $95.5 million of letters of credit were outstanding at Dec. 31, 2003, as discussed in Note 15 to the Consolidated Financial Statements, of which approximately $65 million were outstanding under the various credit facilities, which further reduced amounts available under the lines. The credit facilities of NSP-Minnesota and PSCo are secured, while all other facilities are unsecured.

The SPS $100 million facility expired in February 2004 and was replaced with a $125 million unsecured, 364-day credit agreement.

The borrowing rates under these lines of credit are based on either the bank's published base rate or the applicable London Interbank Offered Rate (LIBOR) plus a euro dollar rate margin.

6. LONG-TERM DEBT

Except for SPS and other minor exclusions, all property of the 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. Annual sinking-fund requirements at Cheyenne are $0.2 million and must be satisfied with cash payments. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS have no sinking-fund requirements for current bonds outstanding.

NSP-Minnesota's 2011 series bonds were redeemable upon seven-days notice at the option of the bondholder. Because the terms allowed the holders to redeem these bonds on short notice, the bonds were classified as a current portion of long-term debt reported under current liabilities on the balance sheet for the year ended Dec. 31, 2002. The bonds were redeemed in October 2003.

Xcel Energy's 2007 and 2008 series convertible senior notes are convertible into shares of Xcel Energy common stock at a conversion price of $12.33 per share. Conversion is at the option of the holder at any time prior to maturity.

Maturities of long-term debt are:

2004	$160 million
2005	$224 million
2006	$838 million
2007	$340 million
2008	$655 million

7. PREFERRED STOCK

At Dec. 31, 2003, 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 11 to the Consolidated Financial Statements 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. In the event that 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. 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 Dec. 31, 2003, 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	1,000,000	$100.00	None
SPS	10,000,000	$ 1.00	None
PSCo	10,000,000	$ 0.01	None

8. MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

Southwestern Public Service Capital I, a wholly owned, special-purpose subsidiary trust of SPS, had $100 million of 7.85-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2036. Distributions paid by the subsidiary trust on the preferred securities were financed through interest payments on debentures issued by SPS and held by the subsidiary trust, which were eliminated in consolidation. Distributions and redemption payments were guaranteed by SPS. The securities were redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. On Oct. 15, 2003, SPS redeemed the $100 million of trust preferred securities. A certificate of cancellation was filed to dissolve SPS Capital I on Jan. 5, 2004.

NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, had $200 million of 7.875-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2037. Distributions paid by the subsidiary trust on the preferred securities were financed through interest payments on debentures issued by NSP-Minnesota and held by the subsidiary trust, which were eliminated in consolidation. Distributions and redemption payments were guaranteed by NSP-Minnesota. The preferred securities were redeemable at NSP Financing I's option at $25 per share, beginning in 2002. On July 31, 2003, NSP-Minnesota redeemed the $200 million of trust preferred securities. A certificate of cancellation was filed to dissolve NSP Financing I on Sept. 15, 2003.

PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, had $194 million of 7.60-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2038. Distributions paid by the subsidiary trust on the preferred securities were financed through interest payments on debentures issued by PSCo and held by the subsidiary trust, which were eliminated in consolidation. Distributions and redemption payments were guaranteed by PSCo. The securities were redeemable at the option of PSCo after May 2003, at 100 percent of the principal amount outstanding plus accrued interest. On June 30, 2003, PSCo redeemed the $194 million of trust preferred securities. A certificate of cancellation was filed to dissolve PSCo Capital Trust I on Dec. 29, 2003.

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

9. JOINT PLANT OWNERSHIP

Following are the investments by Xcel Energy's subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2003:

(Thousands of dollars)	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NSP-Minnesota				
Sherco Unit 3	$617,343	$311,252	$500	59.0
Transmission facilities, including substations	2,761	843	–	59.0
Total NSP-Minnesota	$620,104	$312,095	$ 500	
PSCo				
Hayden Unit 1	$ 85,828	$ 40,764	$ –	75.5
Hayden Unit 2	79,818	43,834	76	37.4
Hayden Common Facilities	27,614	4,010	1,017	53.1
Craig Units 1 & 2	58,224	30,876	80	9.7
Craig Common Facilities Units 1, 2 & 3	19,109	9,246	9,935	6.5–9.7
Transmission Facilities, including substations	112,594	40,779	18,380	42.0–73.0
Total PSCo	$383,187	$169,509	$29,488	

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 and construction expenditures are 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 are included in the applicable utility 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.

10. INCOME TAXES

Xcel Energy's share of NRG results for current and prior periods is now shown as a component of discontinued operations, due to NRG's emergence from bankruptcy in December 2003 and Xcel Energy's corresponding divestiture of its ownership interest in NRG. Accordingly, Xcel Energy's tax benefits related to its investment in NRG are reported in discontinued operations.

Xcel Energy's federal net operating loss and tax credit carry forwards are estimated to be $742 million and $70 million, respectively, after considering a two-year carry back of the loss. The carry forward periods expire in 2023. Xcel Energy also has a net operating loss carry forward in some states. The state carry forward periods expire between 2018 and 2023.

Total income tax expense from continuing operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. Following is a table reconciling such differences:

	2003	2002	2001
Federal statutory rate	**35.0%**	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	**2.2**	3.2	3.6
Life insurance policies	**(3.9)**	(3.3)	(2.4)
Tax credits recognized	**(4.2)**	(4.7)	(2.9)
Regulatory differences – utility plant items	**0.8**	1.5	2.3
Resolution of income tax audits	**(5.2)**	–	–
Other – net	**(1.0)**	(0.8)	(1.2)
Total effective income tax rate	**23.7**	30.9	34.4
Extraordinary item	**–**	–	(0.6)
Effective income tax rate from continuing operations	**23.7%**	30.9%	33.8%

Income taxes comprise the following expense (benefit) items:

(Thousands of dollars)	2003	2002	2001
Current federal tax expense	**$ 107,770**	$104,658	$305,709
Current state tax expense	**(1,194)**	19,864	37,185
Current tax credits	**(15,269)**	(19,079)	(13,544)
Deferred federal tax expense	**77,730**	129,556	(25,547)
Deferred state tax expense	**2,104**	17,301	13,336
Deferred investment tax credits	**(12,499)**	(16,686)	(12,797)
Income tax expense excluding extraordinary items	**158,642**	235,614	304,342
Tax expense on extraordinary items	**–**	–	5,747
Total income tax expense from continuing operations	**$158,642**	$235,614	$310,089

As of Dec. 31, 2002, Xcel Energy management intended to indefinitely reinvest the earnings of the Argentina operations of Xcel Energy International and, therefore, had not provided deferred taxes for the effects of currency devaluations. However, during 2003, the board of directors of Xcel Energy approved management's plan to exit the business conducted by Xcel Energy International. Accordingly, any tax effects are recorded in discontinued operations.

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

(Thousands of dollars)	2003	2002
Deferred tax liabilities:		
Differences between book and tax basis of property	**$1,845,091**	$1,784,754
Regulatory assets	**243,671**	171,292
Employee benefits and other accrued liabilities	**82,186**	63,079
Partnership income/loss	**23,551**	26,778
Service contracts	**18,757**	20,794
Tax benefit transfer leases	**5,330**	10,993
Other	**35,352**	32,086
Total deferred tax liabilities	**$2,253,938**	$2,109,776
Deferred tax assets:		
Deferred investment tax credits	**$ 61,394**	$ 66,472
Other comprehensive income	**55,525**	70,703
Regulatory liabilities	**43,816**	47,579
Net operating loss carry forward	**35,890**	–
Tax credit carry forward	**11,668**	–
Other	**19,778**	27,538
Total deferred tax assets	**$ 228,071**	$ 212,292
Net deferred tax liability	**$2,025,867**	$1,897,484

11. COMMON STOCK AND INCENTIVE STOCK PLANS

Common Stock and Equivalents Xcel Energy has common stock equivalents consisting of convertible senior notes and options, as discussed further.

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

(Shares and dollars in thousands, except per share amounts)	*2003* Income	*2003* Shares	*2003* Per Share Amount	*2002* Income	*2002* Shares	*2002* Per Share Amount	*2001* Income	*2001* Shares	*2001* Per Share Amount
Income from continuing operations	**$510,020**			$527,693			$579,200		
Less: Dividend requirements on preferred stock	**(4,241)**			(4,241)			(4,241)		
Basic earnings per share									
Income from continuing operations	**$505,779**	**398,765**	**$1.27**	$523,452	382,051	$1.37	$574,959	342,952	$1.69
Effect of dilutive securities:									
$230 million convertible debt	**11,213**	**18,654**		1,246	2,027		–	–	
$100 million convertible debt	**–**	**–**		–	445		–	–	
$57.5 million convertible debt	**311**	**507**		–	–		–	–	
Convertible debt option	**–**	**508**		–	–		–	–	
Restricted stock	**–**	**464**		–	–		–	–	
Options	**–**	**14**		–	123		–	790	
Diluted earnings per share									
Income from continuing operations and assumed conversions	**$517,303**	**418,912**	**$1.23**	$524,698	384,646	$1.37	$574,959	343,742	$1.68

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 Xcel Energy's 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 below include awards made by Xcel Energy and some of its 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 was as follows for the years ended Dec. 31:

(Awards in thousands)	*2003* Awards	*2003* Average Price	*2002* Awards	*2002* Average Price	*2001* Awards	*2001* Average Price
Outstanding beginning of year	**16,981**	**$26.29**	15,214	$25.65	14,259	$25.35
Granted	**–**	**–**	–	–	2,581	$25.98
Options transferred from NRG acquisition	**–**	**–**	3,328	$29.97	–	–
Exercised	**(190)**	**$12.21**	(112)	$20.27	(1,472)	$23.00
Forfeited	**(580)**	**$28.48**	(1,349)	$28.43	(142)	$27.08
Expired	**(597)**	**$23.41**	(100)	$28.87	(12)	$24.07
Outstanding at end of year	**15,614**	**$26.49**	16,981	$26.29	15,214	$25.65
Exercisable at end of year	**9,358**	**$25.59**	8,993	$24.78	7,154	$24.78

	Range of Exercise Prices $11.50 to $25.50	*Range of Exercise Prices* $25.51 to $27.00	*Range of Exercise Prices* $27.01 to $51.25
Options outstanding:			
Number outstanding	3,721,340	7,659,232	4,233,224
Weighted average remaining contractual life (years)	4.2	6.3	6.3
Weighted average exercise price	$20.49	$26.29	$32.13
Options exercisable:			
Number exercisable	3,594,809	3,794,565	1,968,619
Weighted average exercise price	$20.58	$26.34	$33.29

Certain employees also may be awarded other restricted stock under Xcel Energy incentive plans. Xcel Energy holds restricted stock until restrictions lapse, generally from two to three years from the date of grant. Xcel Energy reinvests dividends on the shares it holds 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. Xcel Energy did not grant any restricted shares in 2003. Xcel Energy granted 50,083 restricted shares in 2002 when the grant-date market price was $22.83, and 21,774 restricted shares in 2001 when the grant-date market price was $26.06. Compensation expense related to these awards was immaterial.

On March 28, 2003, the compensation and nominating committee of Xcel Energy's board of directors did grant restricted stock units and performance shares under the Xcel Energy omnibus incentive plan approved by the shareholders in 2000. No stock options were granted in 2003. Restrictions on the restricted stock units will lapse after one year from the date of grant, upon the achievement of a 27 percent total shareholder return (TSR) for 10 consecutive business days and other criteria relating to Xcel Energy's common equity ratio. TSR is measured using the market price per share of Xcel Energy common stock, which at the grant date was $12.93, plus common dividends declared after grant date. The TSR was met in the fourth quarter of 2003, and approximately $31 million of compensation expense was recorded at Dec. 31, 2003, based on the expected vesting date (one year after award grant) of March 28, 2004. The remaining costs related to 2003 restricted stock unit awards vesting in 2004 of $10 million will be recorded in the first quarter of 2004. In January 2004, Xcel Energy's board of directors approved the repurchase of 2.5 million shares of common stock to fulfill the requirements of the restricted stock unit exercise in 2004.

Xcel Energy applies Accounting Principles Board Opinion No. 25 – "Accounting for Stock Issued to Employees," in accounting for 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 Xcel Energy's common stock at the date of grant. In December 2002, the FASB issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure," amending SFAS 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. The pro forma impact of applying SFAS No. 148 is as follows at Dec. 31:

(Thousands of dollars)	***2003***	*2002*	*2001*
Net income (loss) – as reported	**$622,392**	$(2,217,991)	$794,966
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**(6,223)**	(6,959)	(3,455)
Pro forma net income	**$616,169**	$(2,224,950)	$791,511
Earnings (loss) per share:			
Basic – as reported	**$ 1.55**	$ (5.82)	$ 2.31
Basic – pro forma	**$ 1.54**	$ (5.84)	$ 2.30
Diluted – as reported	**$ 1.50**	$ (5.77)	$ 2.30
Diluted – pro forma	**$ 1.49**	$ (5.79)	$ 2.29

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:

	2003*	*2002**	*2001*
Weighted-average fair value per option share at grant date	–	–	$2.13
Expected option life	–	–	3–5 years
Stock volatility	–	–	18%
Risk-free interest rate	–	–	3.8–4.8%
Dividend yield	–	–	4.9–5.8%

** There were no options granted in 2003 or 2002.*

Common Stock Dividends Per Share Historically, Xcel Energy has paid quarterly dividends to its shareholders. For each of the four quarters of 2003, Xcel Energy paid dividends to its shareholders of $0.1875 per share. For each of the first two quarters of 2002, Xcel Energy paid dividends to its shareholders of $0.375 per share. In each of the third and fourth quarters of 2002, Xcel Energy 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 the core business through internal cash flow and reducing reliance on debt and equity financings. The board of directors also compared the dividend to utility subsidiary earnings and to the dividend payout of comparable utilities. Dividends on common stock are paid as declared by the board of directors.

Dividend and Other Capital-Related Restrictions Under the PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may declare and pay dividends only out of retained earnings. In May 2003, Xcel Energy received authorization from the SEC to pay an aggregate amount of $152 million of common and preferred dividends out of capital and unearned surplus. Xcel Energy used this authorization to declare and pay approximately $150 million for its first and second quarter dividends in 2003. At Dec. 31, 2003, Xcel Energy's retained earnings were approximately $369 million, after declaring the third and fourth quarter dividends.

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, and 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, the capitalization ratio at Dec. 31, 2003, was 83 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy's 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 Xcel Energy 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 $815 million in additional cash dividends on common stock at Dec. 31, 2003.

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, are limited, under PUHCA, in their ability to issue securities. Such registered holding companies and their subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy does not qualify for any of the main exemptive rules, it sought and received financing authority from the SEC under PUHCA for various financing arrangements. Xcel Energy's current financing authority permits it, subject to satisfaction of certain conditions, to issue through June 30, 2005, up to $2.5 billion of common stock and long-term debt and $1.5 billion of short-term debt at the holding company level. Xcel Energy has $2 billion of long-term debt outstanding and common stock, including the $400 million credit facility.

Xcel Energy's ability to issue securities under the financing authority is subject to a number of conditions. One of the conditions of the financing authority is that Xcel Energy's ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. As of Dec. 31, 2003, such common equity ratio was approximately 43 percent. Additional conditions require that a security to be issued that is rated, be rated investment grade by at least one nationally recognized rating agency. Finally, all outstanding securities (except preferred stock) that are rated must be rated investment grade by at least one nationally recognized rating agency. As of Dec. 31, 2003, Xcel Energy's senior unsecured debt was considered investment grade by at least one nationally recognized rating agency.

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.

12. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 51 percent of benefiting employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2003, NSP-Minnesota had 2,244 and NSP-Wisconsin had 427 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2004 but has been tentatively settled to extend until Dec. 31, 2007. PSCo had 2,167 bargaining employees covered under a collective-bargaining agreement, which expires in May 2006. SPS had 739 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.

Pension Plan Assets 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 percent to 80 percent in equity investments, 5 percent to 10 percent in fixed income investments, no cash investments and 10 percent to 15 percent in nontraditional investments, such as real estate, timber ventures, private equity and venture capital.

The actual composition of pension plan assets at Dec. 31 was:

	2003	*2002*
Equity securities	**75%**	68%
Debt securities	**14**	16
Real estate	**3**	–
Cash	**–**	4
Nontraditional investments	**8**	12
	100%	100%

During 2003, Xcel Energy entered into a number of hedging arrangements within the pension trust designed to provide protection from a loss of asset value in the event of a broad decline in equity prices. These arrangements are expected to expire at the end of 2004. At Dec. 31, 2003, the mark-to-market value of these arrangements was not material to the value of pension trust assets.

Xcel Energy bases its investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. 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. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 12.7 percent, which is in excess of the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long-term. The Xcel Energy portfolio is heavily weighted toward equity securities, includes nontraditional investments that can provide a higher-than-average return, and in 2003 includes derivative financial instruments intended to hedge the risk of potentially volatile performance of other investments. 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. Investment returns in 2001 and 2002 were below the assumed level of 9.5 percent, but in 2003 investment returns exceeded the assumed level of 9.25 percent. Xcel Energy continually reviews its pension assumptions. In 2004, Xcel Energy has changed the investment-return assumption to 9.0 percent to reflect the changing expectations of investment experts in the marketplace.

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

(Thousands of dollars)	*2003*	*2002*
Accumulated Benefit Obligation at Dec. 31	**$2,512,138**	$2,381,214
Change in Projected Benefit Obligation		
Obligation at Jan. 1	**$2,505,576**	$2,409,186
Service cost	**67,449**	65,649
Interest cost	**170,731**	172,377
Acquisitions	**–**	7,848
Plan amendments	**85,937**	3,903
Actuarial loss	**82,197**	65,763
Settlements	**(9,546)**	(994)
Special termination benefits	**–**	4,445
Curtailment gain	**(26,407)**	–
Benefit payments	**(243,446)**	(222,601)
Obligation at Dec. 31	**$2,632,491**	$2,505,576
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$2,639,963**	$3,267,586
Actual return on plan assets	**605,978**	(404,940)
Employer contributions	**31,712**	912
Settlements	**(9,546)**	(994)
Benefit payments	**(243,446)**	(222,601)
Fair value of plan assets at Dec. 31	**$3,024,661**	$2,639,963
Funded Status of Plans at Dec. 31		
Net asset	**$ 392,170**	$ 134,387
Unrecognized transition asset	**(7)**	(2,003)
Unrecognized prior service cost	**273,725**	224,651
Unrecognized (gain) loss	**9,710**	182,927
Net pension amounts recognized on Consolidated Balance Sheets	**$ 675,598**	$ 539,962
Prepaid pension asset recorded *(a)*	**$ 567,227**	$ 466,229
Intangible asset recorded – prior service costs	**5,816**	6,943
Minimum pension liability recorded	**(55,528)**	(106,897)
Accumulated other comprehensive income recorded – pretax	**158,083**	173,687
Measurement Date	**Dec. 31, 2003**	Dec. 31, 2002
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	**6.25%**	6.75%
Expected average long-term increase in compensation level	**3.50%**	4.00%

(a) $19.9 million of the 2003 prepaid pension asset relates to Xcel Energy's remaining obligation for companies that are now classified as discontinued operations, and $17.5 million of the 2002 prepaid pension asset relates to such discontinued operations.

During 2002, one of Xcel Energy's pension plans became under funded, and at Dec. 31, 2003, had projected benefit obligations of $653.1 million, which exceeds plan assets of $563.8 million. All other Xcel Energy plans in the aggregate had plan assets of $2.5 billion and projected benefit obligations of $2.0 billion on Dec. 31, 2003. A minimum pension liability of $55.5 million was recorded related to the under-funded plan as of that date. A corresponding reduction in Accumulated Other Comprehensive Income, a component of Stockholders' Equity, also was recorded, 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 $98.1 million at Dec. 31, 2003, due to the minimum pension liability for the under-funded plan.

A retirement spending account and Social Security supplement for former New Century Energies, Inc. nonbargaining employees was added July 1, 2003, to align it with the Xcel Energy plan formula. Also, the Normal Retirement Age for Xcel Energy's traditional, account balance, and "pension equity" programs was changed to age 65 with one year of service.

Cash Flows 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 the years 2001 through 2003 for Xcel Energy's pension plans, and is not expected to require cash funding in 2004. PSCo elected to make a voluntary contribution of $30 million to its pension plan for bargaining employees in 2003, and it plans to voluntarily contribute another $10 million to the plan in 2004.

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

(Thousands of dollars)	*2003*	*2002*	*2001*
Service cost	**$ 67,449**	$ 65,649	$ 57,521
Interest cost	**170,731**	172,377	172,159
Expected return on plan assets	**(322,011)**	(339,932)	(325,635)
Curtailment (gain) loss	**(17,363)**	–	1,121
Settlement (gain) loss	**(1,135)**	–	–
Amortization of transition asset	**(1,996)**	(7,314)	(7,314)
Amortization of prior service cost	**28,230**	22,663	20,835
Amortization of net gain	**(44,825)**	(69,264)	(72,413)
Net periodic pension cost (credit) under SFAS No. 87 *(a)*	**$(120,920)**	$(155,821)	$(153,726)
Credits not recognized due to effects of regulation	**51,311**	71,928	76,509
Net benefit cost (credit) recognized for financial reporting	**$ (69,609)**	$ (83,893)	$ (77,217)
Significant Assumptions Used to Measure Costs			
Discount rate	**6.75%**	7.25%	7.75%
Expected average long-term increase in compensation level	**4.00%**	4.50%	4.50%
Expected average long-term rate of return on assets	**9.25%**	9.50%	9.50%

(a) Includes pension credits related to discontinued operations of $18.7 million for 2003, $9.6 million for 2002, and $8.2 million for 2001. The 2003 credit is largely due to a $20.0 million curtailment gain related to termination of NRG employees as a result of the divestiture of NRG in December 2003.

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2004 pension cost calculations will be 9.0 percent. 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.

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 $15.9 million in 2003, $18.3 million in 2002, and $29.0 million in 2001.

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. The ESOP component of the 401(k) plan is no longer leveraged.

Xcel Energy's leveraged ESOP held 10.7 million shares of Xcel Energy common stock at May 6, 2002, and 10.5 million shares of Xcel Energy common stock at the end of 2001. Xcel Energy excluded an average of 0.7 million in 2002 and 0.9 million in 2001 of uncommitted leveraged ESOP shares from earnings-per-share calculations. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and were 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. Xcel Energy discontinued contributing toward health care benefits for former NCE nonbargaining employees retiring after June 30, 2003. Employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Nonbargaining employees of the former NSP who retired after 1998; bargaining employees of the former NSP who retired after 1999; and nonbargaining employees of the former NCE who retired after June 30, 2003, 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.

Plan Assets Certain state agencies that regulate Xcel Energy's utility subsidiaries also have 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 was tax advantaged. The investment strategy for the postretirement health care fund assets is fairly conservative, with minimal exposure to equity markets and a focus on fixed income and cash equivalents to preserve investment capital while earning modest income.

The actual composition of postretirement benefit plan assets at Dec. 31 was:

	2003	*2002*
Fixed income/debt securities	**2%**	2%
Equity mutual fund securities	**14**	12
Cash equivalents	**84**	85
Other	**–**	1
	100%	100%

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its postretirement health care asset portfolio. Given the fairly short time period in which funding has been required, Xcel Energy does not consider the actual historical returns achieved by its postretirement health care fund asset portfolio to be significant in establishing long-term return assumptions. Instead, Xcel Energy considers the long-term return levels projected and recommended by investment experts, weighted for the target mix of asset categories in our portfolio. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

Benefit Obligations 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)	*2003*	*2002*
Change in Benefit Obligation		
Obligation at Jan. 1	**$767,975**	$687,455
Service cost	**5,893**	7,173
Interest cost	**52,426**	50,135
Acquisitions (divestitures)	**(31,584)**	773
Plan amendments	**(33,304)**	–
Plan participants' contributions	**16,577**	5,755
Actuarial loss	**122,864**	61,276
Special termination benefits	**–**	(173)
Curtailments	**(249)**	–
Benefit payments	**(60,754)**	(44,419)
Impact of Medicare Prescription Drug, Improvement and Modernization Act of 2003	**(64,614)**	–
Obligation at Dec. 31	**$775,230**	$767,975
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$250,983**	$242,803
Actual return on plan assets	**11,045**	(13,632)
Plan participants' contributions	**16,577**	5,755
Employer contributions	**68,010**	60,476
Benefit payments	**(60,754)**	(44,419)
Fair value of plan assets at Dec. 31	**$285,861**	$250,983
Funded Status at Dec. 31		
Net obligation	**$489,369**	$516,992
Unrecognized transition asset (obligation)	**(69,164)**	(169,328)
Unrecognized prior service cost	**20,093**	10,904
Unrecognized gain (loss)	**(319,788)**	(206,601)
Accrued benefit liability recorded *(a)*	**$120,510**	$151,967
Measurement Date	**Dec. 31, 2003**	Dec. 31, 2002
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	**6.25%**	6.75%

(a) ($0.6) million of the 2003 accrued benefit liability relates to Xcel Energy's remaining obligation for companies that are now classified as discontinued operations, and $28.3 million of the 2002 accrued benefit liability relates to such discontinued operations.

The assumed health care cost trend rate for 2003 for most Xcel Energy plans is approximately 7.5 percent, decreasing gradually to 5.5 percent in 2007 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, 2003	$ 95.8
1-percent decrease in APBO components at Dec. 31, 2003	$(79.4)
1-percent increase in service and interest components of the net periodic cost	$ 7.3
1-percent decrease in service and interest components of the net periodic cost	$ (6.0)

The employer subsidy for retiree medical coverage was eliminated for former New Century Energies, Inc. nonbargaining employees who retire after July 1, 2003.

Xcel Energy's subsidiary Viking Gas Transmission Co. was sold on Jan. 17, 2003. The sale created a one-time curtailment gain of $0.8 million. NRG participants withdrew from the retiree life plan, resulting in a $1.3 million one-time curtailment gain in 2003.

NRG employees' participation in the Xcel Energy postretirement health care plan ended when NRG emerged from bankruptcy on Dec. 5, 2003. A settlement gain of $0.9 million was recognized.

Cash Flows The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy expects to contribute approximately $51.4 million during 2004.

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

(Thousands of dollars)	*2003*	*2002*	*2001*
Service cost	**$ 5,893**	$ 7,173	$ 6,160
Interest cost	**52,426**	50,135	46,579
Expected return on plan assets	**(22,185)**	(21,030)	(18,920)
Curtailment (gain) loss	**(2,128)**	–	–
Settlement (gain) loss	**(916)**	–	–
Amortization of transition obligation	**15,426**	16,771	16,771
Amortization of prior service cost (credit)	**(1,533)**	(1,130)	(1,235)
Amortization of net loss (gain)	**15,409**	5,380	1,457
Net periodic postretirement benefit cost (credit) under SFAS No. 106 *(a)*	**62,392**	57,299	50,812
Additional cost recognized due to effects of regulation	**3,883**	4,043	3,738
Net cost recognized for financial reporting	**$66,275**	$61,342	$54,550
Significant assumptions used to measure costs (income)			
Discount rate	**6.75%**	7.25%	7.75%
Expected average long-term rate of return on assets (pretax)	**8.0%–9.0%**	9.0%	8.0%–9.5%

(a) Includes amounts related to discontinued operations of ($3.0) million of credit in 2003, $2.7 million of cost in 2002, and $2.0 million of cost in 2001.

Impact of 2003 Medicare Legislation On Dec. 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. This new coverage is generally effective Jan. 1, 2006. Many of Xcel Energy's retiree medical programs provide prescription drug coverage for retirees over age 65 with coverage at least equivalent to the benefit to be provided under Medicare. While retirees remain in Xcel Energy's postretirement health care plan without participating in the new Medicare prescription drug coverage, Medicare will share the cost of Xcel Energy's plan. This legislation has therefore reduced Xcel Energy's share of the obligation for future retiree medical benefits.

The postretirement health care benefit obligation shown in the chart previously is the actuarial present value, as of Dec. 31, 2003, of Xcel Energy's share of future retiree medical benefits attributable to service through the current year. This obligation has been reduced to reflect the effects of this legislation. The FASB has not yet issued authoritative guidance on the method it prefers to reflect the Act in these calculations. In addition, regulations implementing this legislation have not yet been issued by Medicare agencies. As a result, when guidance and regulations are issued, the estimates of future costs and obligations could change and previously estimated information may require revision.

As of Dec. 31, 2003, Xcel Energy had reduced the postretirement health care benefit obligation by $64.6 million due to the expected sharing of the cost of the program by Medicare under the new legislation. Also, beginning in 2004, it is expected that the annual net periodic postretirement benefit cost will be reduced by approximately $10 million as a result of the expected sharing of the cost of the program by Medicare, with similar savings in subsequent years. This reduction includes both the decrease in the cost of future benefits being earned during this year, and an amortization of the benefit obligation reduction, previously noted, over approximately nine years. These estimated reductions do not reflect any changes that may result in future levels of participation in the plan or the associated per capita claims cost due to the availability of prescription drug coverage for Medicare-eligible retirees. Also, in reflecting this legislation, Medicare cost sharing for a plan has been assumed only if Xcel Energy's projected contribution to the plan is expected to be at least equal to the Medicare Part D basic benefit.

13. DETAIL OF INTEREST AND OTHER INCOME, NET OF NONOPERATING EXPENSES

Interest and other income, net of nonoperating expenses, for the years ended Dec. 31, comprises the following:

(Thousands of dollars)	*2003*	*2002*	*2001*
Interest income	**$16,589**	$29,559	$21,589
Equity income in unconsolidated affiliates	**5,628**	1,835	7,029
Gain on disposal of assets	**9,365**	10,076	14,696
Allowance for funds used during construction	**25,338**	7,793	6,739
Other nonoperating income	**3,169**	13,937	817
Interest expense on corporate-owned life insurance	**(24,372)**	(18,523)	(20,116)
Total interest and other income, net of nonoperating expenses	**$35,717**	$44,677	$30,754

14. EXTRAORDINARY ITEMS

SPS In April 2003, New Mexico enacted legislation that repealed its Electric Utility Restructuring Act of 1999, as amended. The implementation of restructuring had been delayed in 2001. The legislation provides that a public utility be entitled to an opportunity to recover its transition costs. Utilities, including SPS, may retain the transition costs as a regulatory asset on their books pending recovery, which shall be completed by January 2010.

In June 2001, the governor of Texas signed legislation postponing the retail competition and restructuring for 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 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 in Texas and New Mexico, SPS' previous plans to implement restructuring, including the divestiture of generation assets, have been abandoned. Accordingly, SPS will 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 (at least until 2007).

During the fourth quarter of 2001, SPS completed a $500 million, medium-term debt financing. The proceeds were used to reduce short-term borrowings that had resulted from the 2000 defeasance of first mortgage bonds. 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.

15. FINANCIAL INSTRUMENTS

Fair Values

The estimated Dec. 31 fair values of Xcel Energy's recorded financial instruments, separately identifying amounts that are within continuing operations and amounts included related to discontinued operations, are as follows:

	2003		*2002*	
(Thousands of dollars)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Continuing Operations				
Mandatorily redeemable preferred securities of subsidiary trust	**$ –**	**$ –**	$ 494,000	$ 463,348
Long-term investments	**$ 828,802**	**$ 827,375**	$ 649,160	$ 647,395
Notes receivable, including current portion	**$ 12,643**	**$ 12,643**	$ 5,352	$ 5,352
Long-term debt, including current portion	**$6,678,808**	**$7,363,457**	$5,877,220	$6,123,173
Discontinued Operations				
Long-term investments	**$ –**	**$ –**	$ 4,048	$ 4,048
Notes receivable, including current portion	**$ 826**	**$ 826**	$ 990,815	$ 990,815
Long-term debt, including current portion	**$ –**	**$ –**	$8,875,018	$6,048,886

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 is primarily a $10 million unsecured note from NRG to Xcel Energy that was part of the NRG bankruptcy settlement for intercompany claims Xcel Energy had against NRG. The term of the note is 30 months and the interest rate is 3 percent. The fair values of Xcel Energy's long-term debt and 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, 2003 and 2002. 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.

Guarantees

Xcel Energy provides 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 guarantee. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral. On Dec. 31, 2003, Xcel Energy had the following amount of guarantees and exposure under these guarantees, including those related to e prime, which is a component of discontinued operations:

(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 *(d)(f)(i)*	Xcel Energy	$ 32.3	$ 4.1	2004, 2005, 2007, 2012, 2014, 2015 and 2022	*(e)*	N/A
Guarantee performance and payment of surety bonds for those subsidiaries	Various subsidiaries *(a)(i)*	$550.8	$47.3	2004 and 2005	*(e)*	$20.0
Guarantees made to facilitate e prime's natural gas acquisition, marketing and trading operations	Xcel Energy	$ 47.0	$ 5.0	Continuing	*(b)*	N/A
Two guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements	Xcel Energy	$ 26.5	–	2011 and 2013	*(b)*	N/A
Guarantee the indemnification obligations of Xcel Energy Markets Holdings Inc. under a purchase agreement with Border Viking Co.	Xcel Energy	$ 30.7	–	Continuing	*(c)*	N/A
Guarantees for e prime Energy Marketing Inc. and e prime Florida Inc.'s guaranteeing payments of energy, capacity and financial transactions	Xcel Energy	$ 13.0	$ 0.1	Continuing	*(b)*	N/A
Guarantee for payments related to energy or financial transactions for XERS Inc., a nonregulated subsidiary of Xcel Energy	Xcel Energy	$ 10.0	$ 0.5	Continuing	*(b)*	N/A
Guarantee of customer loans to encourage business growth and expansion	NSP-Wisconsin	$ 0.7	$ 0.2	Latest expiration in 2006	*(g)*	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$ 2.1	$ 2.1	Latest expiration in 2007	*(b)*	*(h)*
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$ 5.9	–	Continuing	*(b)*	N/A

(a) The $47.3 million exposure is related to $550.1 million of performance bonds associated with six 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.

(b) Nonperformance and/or nonpayment.

(c) Losses caused by default in performance of covenants or breach of any warranty or representation in the purchase agreement.

(d) Includes two performance bonds with a notional amount of $13.3 million that guarantee the performance of Planergy Housing Inc., a subsidiary of Xcel Energy that was sold to Ameresco Inc. on Dec. 12, 2003. Ameresco Inc. has agreed to indemnify Xcel Energy for any liability arising out of any surety bond.

(e) 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.

(f) Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. There were approximately $32.3 million of bonds with this indemnity outstanding on Dec. 31, 2003, including $4.2 million related to NRG. However, under the NRG bankruptcy settlement, NRG deposited cash with Xcel Energy that, on Feb. 6, 2004, was replaced with a letter of credit such that Xcel Energy has no further exposure under these indemnities.

(g) Non-timely payment of the obligations or at the time the Debtor becomes the subject of bankruptcy or other insolvency proceedings.

(h) Security interest in underlying receivable agreements.

(i) On Jan. 19, 2004, Xcel Energy entered into an agreement with an insurance company for the purpose of indemnifying that insurance company in connection with surety bonds they may issue or have issued for Utility Engineering up to an amount of $80 million. The Xcel Energy indemnification will only be triggered in the event that Utility Engineering has failed to meet its obligations to the surety company.

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, 2003 and 2002. For more detailed information regarding derivative financial instruments and the related risks, see Note 16 to the Consolidated Financial Statements.

Interest Rate Swaps Subsidiaries of Xcel Energy had interest rate swaps outstanding with a notional amount of approximately $256 million, and a fair value that was a liability of approximately $18 million, at Dec. 31, 2003. On Dec. 31, 2002, subsidiaries of Xcel Energy 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.

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 Statement of Operations for 2001 has been reclassified to be consistent. In earlier presentations, the gross accounting method was used. All financial derivative contracts are recorded at the amount of the gain or loss received from the contract. The mark-to-market adjustments for these transactions are reported in the Consolidated Statements of Operations in Electric and Gas Trading Margin.

Regulated Operations Xcel Energy's regulated utility energy marketing operations use 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, 2003, the notional amount of these contracts was approximately 56 million MMBtu of natural gas and 62,400 megawatt-hours of electricity. The fair value of these contracts as of Dec. 31, 2003, was approximately $(11.2) 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, 2003, the notional amount of these contracts was approximately 6.6 million MMBtu of natural gas. The fair value of these contracts as of Dec. 31, 2003, was approximately $1.5 million. The value of hedges related to nonregulated operations is included in discontinued operations.

Foreign Currency Xcel Energy and its subsidiaries have no foreign currency swaps to hedge or protect foreign currency denominated cash flows at Dec. 31, 2003.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2003, there was $95.5 million of letters of credit outstanding. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

16. DERIVATIVE VALUATION AND FINANCIAL IMPACTS

Use of Derivatives to Manage Risk

Business and Operational Risk Xcel Energy and its subsidiaries, including discontinued operations held for sale, 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, Xcel Energy recovers 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 it 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 Xcel Energy and its subsidiaries use various physical contracts and derivative instruments to reduce the volatility in the cost of natural gas and electricity provided to 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 have been 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, primarily through NRG and Xcel Energy International. With the divestiture of NRG and the expected sale of Xcel Energy International, the exposure to market price risk has greatly decreased. Xcel Energy managed this market price risk by entering into firm power sales agreements for approximately 55 percent 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, Xcel Energy managed 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 management of market price risks, and provides guidelines for the level of price risk exposure that is acceptable within the company's operations.

Interest Rate Risk Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

Xcel Energy engages in hedges of cash flow exposure and hedges of fair value exposure. The fair value of interest rate swaps designated as cash flow hedges are initially recorded in Other Comprehensive Income. Reclassification of unrealized gains or losses on cash flow hedges of variable rate debt instruments from Other Comprehensive Income into earnings occurs as interest payments are accrued on the debt instrument and generally offsets the change in the interest accrued on the underlying variable rate debt. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or firm commitment. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments. In order to test the effectiveness of such swaps, a hypothetical swap is used to mirror all the critical terms of the underlying debt and regression analysis is utilized to assess the effectiveness of the actual swap at inception and on an ongoing basis. The assessment is done periodically to ensure the swaps continue to be effective. The fair value of interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

Currency Exchange Risk During 2003 and 2002, NRG and Xcel Energy International, both of which are included in discontinued operations, held certain investments in foreign countries, exposing them to foreign currency exchange risk. The foreign currency exchange risk included the risk relative to the recovery of net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. These subsidiaries managed their exposure to changes in foreign currency by entering into derivative instruments as determined by management. Xcel Energy's risk management policy provided for this risk management activity.

Trading Risk Xcel Energy's subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and, prior to December 2003, through e prime for natural gas. The trading operations are conducted in the United States 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 comprising management personnel not involved in the trading operations.

Derivatives as Hedges

Xcel Energy and its subsidiaries record all derivative instruments on the balance sheet at fair value unless exempted as a normal purchase or sale. Changes in non-exempt derivative instrument's fair value are 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, as amended, 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 currently recognized 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 hedges on Xcel Energy's Other Comprehensive Income, included in the Consolidated Statements of 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 hedges 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 hedges at Dec. 31, 2002	$ 22.1
After-tax net unrealized gains related to derivatives accounted for as hedges	24.1
After-tax net realized gains on derivative transactions reclassified into earnings	(38.1)
Accumulated other comprehensive income related to hedges at Dec. 31, 2003	**$ 8.1**

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as a separate line item identified 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 variability of future cash flows from changes in commodity prices. 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, 2003, Xcel Energy had various commodity-related contracts deemed as cash flow hedges extending through 2009. Amounts deferred are recorded in earnings as the hedged purchase or sales transaction is settled. This could include the physical purchase or sale of electric energy, the use of natural gas to generate electric energy or gas purchased for resale. As of Dec. 31, 2003, Xcel Energy had net losses of $0.7 million accumulated in Other Comprehensive Income that are expected to be recognized in earnings or deferred as a regulatory liability during the next 12 months as the hedged transactions settle. However, due to the volatility of commodities markets, the value in Other Comprehensive Income will likely change prior to its recognition in earnings or deferral as a regulatory liability.

Xcel Energy recorded gains of $0 and $0.4 million related to ineffectiveness on commodity cash flow hedges during the years ended Dec. 31, 2003 and 2002, respectively.

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 the next 12 months net losses from Other Comprehensive Income of approximately $1.6 million.

Xcel Energy and its subsidiaries also enter into interest rate lock agreements that effectively fix the yield or price on a specified treasury security for a specific period. 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 the next 12 months net gains from Other Comprehensive Income of approximately $1.4 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; hedging transactions for gas purchased for resale are recorded as a component of gas costs; and hedging transactions for interest rate swaps and interest rate lock agreements are recorded as a component of interest expense. Certain Xcel Energy utility subsidiaries are allowed to recover in electric or gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility.

Fair Value Hedges Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively hedge the fair value of fixed rate debt. In June 2003, Xcel Energy entered into two five-year swaps, with a $97.5 million notional value each, against Xcel Energy's $195 million 3.40-percent senior notes due 2008. Xcel Energy entered into the swaps to obtain greater access to the lower borrowing costs normally available on floating-rate debt. These swap agreements involve the exchange of amounts based on a variable rate of six-month London Interbank Offered Rate (LIBOR) plus an adder rate over the life of the agreement. The difference to be paid or received as interest rates change is accrued and recognized as an adjustment of interest expense related to the debt. The fair market value of Xcel Energy's interest rate swaps at Dec. 31, 2003, was $(6.3) million.

Hedges of Foreign Currency Exposure of a Net Investment in Foreign Operations Due to the discontinuance of NRG and Xcel Energy International's operations in 2003, as discussed in Notes 3 and 4 to the Consolidated Financial Statements, Xcel Energy no longer has foreign currency exposure.

During 2002, to preserve the U.S. dollar value of projected foreign currency cash flows, Xcel Energy, through NRG, hedged those cash flows if appropriate foreign hedging instruments were available. Xcel Energy recorded unrealized losses of $0.8 million associated with changes in the fair value of non-hedge, foreign currency derivative instruments for the year ended Dec. 31, 2002. In addition, Xcel Energy recorded losses of $2.3 million related to the discontinuance of hedge accounting for the year ended Dec. 31, 2002.

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. The results of these transactions are recorded within Operating Revenues on the Consolidated Statements of Operations.

Normal Purchases or Normal Sales Contracts Xcel Energy's utility subsidiaries enter into contracts for the purchase and sale of various commodities for use in their 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 amended, 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. In addition, normal purchase and normal sales contracts must have a price based on an underlying that is clearly and closely related to the asset being sold or purchased. An underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event such as a scheduled payment under a contract. Contracts that meet the requirements of normal are documented and exempted from the accounting and reporting requirements of SFAS No. 133. In June 2003, the Derivatives Implementation Group of FASB issued Implementation Issue No. C20 (C20) to clarify the circumstances when an underlying is not clearly and closely related to the asset being sold or purchased. Xcel Energy's implementation of C20 in 2003 had no impact on earnings. However, certain contracts did require a one-time fair value adjustment as of Oct. 1, 2003. The result of this adjustment was the creation of a derivative liability with an offsetting regulatory asset to reflect expected recovery of the amounts from customers. The derivative asset and related regulatory liability will be amortized over the respective lives of the contracts. See Note 19 to the Consolidated Financial Statements.

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 operations qualify for a normal designation.

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

17. COMMITMENTS AND CONTINGENCIES

Commitments

Legislative Resource Commitments In 1994 and 2003, 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. The use of 29 dry cask containers has been approved. As of Dec. 31, 2003, NSP-Minnesota had loaded 17 of the containers.

In 1994, as a condition of approving 17 dry cask storage 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.

On May 29, 2003, the Minnesota Legislature enacted additional legislation, which will enable NSP-Minnesota to store at least 12 more casks of spent fuel outside the Prairie Island nuclear generating plant. This will allow NSP-Minnesota to continue to operate the facility and store spent fuel there until its licenses with the Nuclear Regulatory Commission (NRC) expire in 2013 and 2014. The legislation transfers the primary authority concerning future spent-fuel storage issues from the state Legislature to the MPUC. It also allows for additional storage without the requirement of an affirmative vote from the state Legislature, if the NRC extends the licenses of the Prairie Island and Monticello plants and the MPUC grants a certificate of need for such additional storage. The legislation requires NSP-Minnesota to add at least 300 megawatts of additional wind power by 2010 with an option to own 100 megawatts of this power.

The legislation also requires payments during the remaining operating life of the Prairie Island plant. These payments include: $2.25 million per year to the Prairie Island Tribal Community beginning in 2004; 5 percent of NSP-Minnesota's conservation-program expenditures (estimated at $2 million per year) to the University of Minnesota for renewable energy research; and an increase in funding commitments to the previously established Renewable Development Fund from $8.5 million in 2002 to $16 million per year beginning in 2003. The legislation also designated $10 million in one-time grants to the University of Minnesota for additional renewable energy research, which is to be funded from commitments already made to the Renewable Development Fund. All of the cost increases to NSP-Minnesota from these required payments and funding commitments are expected to be recoverable in Minnesota retail customer rates, mainly through existing cost recovery mechanisms. Funding commitments to the Renewable Development Fund would terminate after the Prairie Island plant discontinues operation unless the MPUC determines that NSP-Minnesota failed to make a good faith effort to move the waste, in which case NSP-Minnesota would have to make payments in the amount of $7.5 million per year.

Reliability Commitments In 2002, the MPUC directed the Office of the Attorney General and the Minnesota Department of Commerce (state agencies) to investigate the accuracy of NSP-Minnesota's electric reliability records, which are summarized and reported to the MPUC on a monthly and annual basis, subject to penalty for not meeting threshold requirements, under the terms of the merger settlement agreements.

In 2003, NSP-Minnesota and the state agencies announced that they had reached a settlement agreement, which was approved with modifications by the MPUC in January 2004. Initially, the settlement requires NSP-Minnesota to refund $1 million to customers in Minnesota, which has been accrued. In addition, it requires NSP-Minnesota to incur at least $15 million of costs for actions to improve system reliability above amounts being currently recovered in rates by Jan. 1, 2005. The MPUC modified the settlement to include an additional under-performance payment for any future finding of inaccurate reliability data. The final order has not yet been issued by the MPUC, and all parties to the settlement have the option to void the settlement in the event of a significant modification to the settlement.

Capital Commitments As discussed in Liquidity and Capital Resources under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2003, of the capital expenditure programs and other capital requirements of Xcel Energy and its subsidiaries is approximately $1.4 billion in 2004, $1.5 billion in 2005 and $2.1 billion in 2006.

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 restructuring requirements, compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Leases Xcel Energy and its 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 in 2024 and 2025. The net book value of property under capital leases was approximately $48 million and $50 million at Dec. 31, 2003 and 2002, 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 for continuing operations was approximately $66 million, $69 million and $49 million for 2003, 2002 and 2001, respectively.

Future commitments under operating and capital leases for continuing operations are:

(Millions of dollars)	*Operating Leases*	*Capital Leases*
2004	$49	$ 7
2005	$49	$ 7
2006	$47	$ 7
2007	$42	$ 7
2008	$40	$ 6
Thereafter	$46	$ 72
Total minimum obligation		$106
Interest		(58)
Present value of minimum obligation		$ 48

Technology Agreement Xcel Energy has 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 2003, Xcel Energy paid IBM $114.2 million under the contract and $19.4 million for other project business. The contract also has a committed minimum payment each year from 2004 through 2011.

Fuel Contracts Xcel Energy and its subsidiaries have 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 2004 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.7 billion of coal, $93.3 million of nuclear fuel and $1.9 billion of natural gas, including $790.8 million of natural gas storage and transportation, or to make payments in lieu thereof, under these contracts. Of these minimum purchase commitments, approximately $2 billion are based on indexed prices. 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 use of natural gas and energy cost-adjustment mechanisms of the ratemaking process, which provide for pass-through of most fuel costs to customers.

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 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost-recovery mechanisms.

At Dec. 31, 2003, 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)	
2004	$ 552,651
2005	554,603
2006	547,987
2007	562,917
2008 and thereafter	3,958,416
Total	$6,176,574

Environmental Contingencies

Xcel Energy is 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. Compliance is continually assessed. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating facilities.

Site Remediation Xcel Energy 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, 2003, there were three categories of sites:

- third-party sites, such as landfills, to which Xcel Energy is 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.

Xcel Energy records a liability when enough information is obtained 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, assumptions are made when facts are not fully known. For instance, assumptions may be made 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.

Estimates are revised as facts become known. At Dec. 31, 2003, the liability for the cost of remediating these sites was estimated to be $43.2 million, of which $12.5 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. Estimates have been recorded for Xcel Energy's share of future costs for these sites. Management is not aware of other parties' inability to pay, or responsibility for any of the sites that is in dispute.

Approximately $10.1 million of the long-term liability and $4.5 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 18 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, which was previously an MGP facility, and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and 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 $4.0 million and $93.0 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, NSP-Wisconsin's share of the ultimate cost of remediating the Ashland site is not determinable.

In the interim, NSP-Wisconsin has recorded a liability of $18.5 million for its estimate of its share of the cost of remediating the Ashland site, 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 based on an expectation 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. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed as part of the Wisconsin biennial retail rate case process for prudence. Once approved by the PSCW, deferred MGP remediation costs, less carrying costs, are historically amortized over four or six years. In addition, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers.

As an interim action, Xcel Energy proposed, and the EPA and WDNR have approved, a coal tar removal and groundwater treatment system for one area of concern 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. On Nov. 14, 2003, the EPA and NSP-Wisconsin signed an administrative order on consent requiring NSP-Wisconsin to complete the remedial investigation and feasibility study for the site. Resolution of Ashland remediation issues is not expected until 2006 or 2007. 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.

Fort Collins Manufactured Gas Plant Site Prior to 1926, Poudre Valley Gas Co., a predecessor of PSCo, operated a manufactured gas plant in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the Poudre Valley Gas Co., PSCo shut down the gas site and, years later, sold most of the property. In the mid-1990s, contamination associated with MGP operations was discovered on the gas plant site, and PSCo paid for a portion of a partial cleanup. Recently, an oily substance similar to MGP by-products has been discovered in the Cache la Poudre River. The source of this substance has not yet been identified. PSCo is working with the EPA, the Colorado Department of Public Health and Environment, the current site owner and the City of Fort Collins (owner of a former landfill property between the river and the plant site) to address the substance found in the river as well as other environmental issues found on the property. The scope of the investigation has expanded as a result of negotiations with the EPA, and PSCo estimates that the cost of initial removal and investigation activities will be approximately $1.6 million, although the actual cost will vary depending on site conditions. While PSCo has recorded this cost estimate at Dec. 31, 2003, it lacks sufficient information at this time to estimate its ultimate liability, if different, for this site. PSCo has deferred the cost recorded to date as a regulatory asset and believes that they will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

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 are expected to allow to be recovered from 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 the related revenue to be collected from 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 a portion of the cost of remediating another former MGP site in Grand Forks, N.D. The $2.9 million of deferred cost of remediating that site was accumulated in a regulatory asset that is now being expensed evenly over eight years commensurate with cost recovery. NSP-Minnesota may request recovery of costs to remediate other sites following the completion of preliminary investigations. NSP-Wisconsin has investigated and remediated MGP sites in Wisconsin. As discussed above, external MGP costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed as part of the Wisconsin biennial retail rate case process for prudence. Once approved by the PSCW, deferred MGP amounts, less carrying costs, are historically amortized over four or six years.

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since the intent is to operate most of these facilities indefinitely, Xcel Energy cannot estimate the amount or timing of payments for final removal of the asbestos. 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 approved PSCo's plan 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. In 2003, PSCo began flooding 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. In August 2003, the Colorado Oil and Gas Conservation Commission approved the closure plan, the last formal regulatory approval necessary before conversion. Leyden is expected to close by Dec. 31, 2005, and the city of Arvada will take over the site. PSCo is obligated to monitor the site for two years after closure. As of Dec. 31, 2003, PSCo has incurred approximately $4.7 million of costs associated with engineering buffer studies, damage claims paid to landowners and other initial closure costs. PSCo has accrued an additional $4.7 million of costs expected to be incurred through 2006 to complete the decommissioning and closure of the facility. PSCo has deferred these costs as a regulatory asset and 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 U.S. 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. The suit is 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 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, PSCo 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. PSCo 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. PSCo also believes that the projects would be expressly authorized under the EPA's NSR equipment-replacement rulemaking promulgated in October 2003. On Dec. 24, 2003, the U.S. Court of Appeals for the District of Columbia Circuit stayed this rule while it considers challenges to it. PSCo 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 PSCo 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 PSCo 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 PSCo is not determinable at this time.

NSP-Minnesota NSR Information Request On Nov. 3, 1999, the U.S. Department of Justice filed suit, related to alleged modifications of electric generating stations located in the South and Midwest, against a number of electric utilities for alleged violations of the Clean Air Act's NSR requirements. 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 $10.9 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $10.6 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 $100.6 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 $2.0 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $7.5 million for business interruption insurance and $25.6 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

In the normal course of business, Xcel Energy is subject to 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.

Department of Labor Audit In 2001, Xcel Energy received notice from the Department of Labor (DOL) Employee Benefit Security Administration that it intended to audit the Xcel Energy pension plan. After multiple on-site meetings and interviews with Xcel Energy personnel, the DOL indicated on Sept. 18, 2003, that it is prepared to take the position that Xcel Energy, as plan sponsor and through its delegate, the Pension Trust Administration Committee, breached its fiduciary duties under the Employee Retirement Income Security Act of 1974 (ERISA) with respect to certain investments made in limited partnerships and hedge funds in 1997 and 1998.

All discussions related to potential ERISA fiduciary violations have been preliminary and unofficial. The DOL has offered to conclude the audit at this time if Xcel Energy is willing to contribute to the plan the full amount of losses from each of these questioned investments, or approximately $13 million. Xcel Energy has responded with a letter to the DOL asserting that no fiduciary violations have occurred, and extended an offer to meet to discuss the matter further. In December 2003, the DOL requested, and Xcel Energy agreed, to toll the statute of limitations under ERISA with respect to this claim. The DOL now has until Dec. 5, 2004, to assert a claim. If the DOL offer is put into effect, the requested contribution would affect cash flows only and not the net income of Xcel Energy.

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 U.S. District Court for the District of Minnesota. The complaint named Xcel Energy; Wayne H. Brunetti, chairman 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 filing 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, then president of Xcel Energy Enterprises; two former executive officers and one current executive officer 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 as 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 by NRG. The amended complaint seeks compensatory and rescissionary damages, interest and an award of fees and expenses. On Sept. 30, 2003, in response to the defendants' motion to dismiss, the court issued an order dismissing the claims brought by purchasers of the NRG Senior Notes against defendants James Howard, Gary R. Johnson, Richard C. Kelly, David H. Peterson, Leonard A. Bluhm, William T. Pieper and Luella Goldberg. The court, however, denied the motion related to claims brought by Xcel Energy shareholders against Xcel Energy, James Howard, Wayne Brunetti and Edward McIntyre. Subsequently, following a pre-trial conference in December 2003, this matter was ordered to be ready for trial by Feb. 1, 2006. Presently the parties are in the preliminary stages of discovery.

Xcel Energy Inc. Shareholder Derivative Action; Essmacher vs. Brunetti; McLain vs. Brunetti On Aug. 15, 2002, a shareholder derivative action was filed in the U.S. 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, and an amended complaint was filed. After the filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minn., 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 filed motions to dismiss the complaint or amended 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 in federal court have not been ruled upon. In an order dated Jan. 6, 2004, the Minnesota district court judge granted the defendants' motion to dismiss both of the state court actions. Discovery is proceeding in conjunction with the securities litigation previously described.

Newcome vs. Xcel Energy Inc.; Barclay vs. Xcel Energy Inc. On Sept. 23, 2002 and Oct. 9, 2002, two essentially identical actions were filed in the U.S. 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, James J. Howard and Giannantonio Ferrari, and certain present and former officers, Edward J. McIntyre and David E. Ripka. The complaints allege violations of the ERISA 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, and discovery is proceeding in conjunction with the securities litigation previously described. 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.

SchlumbergerSema, Inc. vs. Xcel Energy Inc. Under a 1996 data services agreement, SchlumbergerSema, Inc. (SLB) provides automated meter reading, distribution automation, and other data services to NSP-Minnesota. In September 2002, NSP-Minnesota issued written notice that SLB committed events of default under the agreement, including SLB's nonpayment of approximately $7.4 million for distribution automation assets. In November 2002, SLB demanded arbitration and asserted various claims against NSP-Minnesota totaling $24 million for alleged breach of an expansion contract and a meter purchasing contract. In the arbitration, NSP-Minnesota asserts counterclaims against SLB including those related to SLB's failure to meet performance criteria, improper billing, failure to pay for use of NSP-Minnesota owned property and failure to pay $7.4 million for NSP-Minnesota distribution automation assets, for total claims of approximately $41 million. NSP-Minnesota also seeks a declaratory judgment from the arbitrators that would terminate SLB's rights under the data services agreement. The arbitration panel is scheduled to hear dispositive motions in March 2004. In the event the matter is not disposed of on the motions, a hearing to arbitrate the dispute will likely occur in second quarter 2004.

Cornerstone Propane Partners, L.P., et al., vs. e prime, inc., et al. In February 2004, a purported class action complaint was filed in the U.S. District Court for the Southern District of New York against e prime and three other defendants, by Cornerstone Propane Partners, L.P., Robert Calle Gracey and Dominick Viola on behalf of a class who purchased or sold one or more New York Mercantile Exchange natural gas futures and/or options contracts during the period from Jan. 1, 2000 to Dec. 31, 2002. The complaint alleges that defendants manipulated the price of natural gas futures and options and/or the price of natural gas underlying those contracts in violation of the Commodities Exchange Act. On Feb. 2, 2004, the plaintiff requested that this action be consolidated with a similar suit involving Reliant Energy Services. Xcel Energy is in the process of reviewing this recently filed complaint and intends to vigorously defend itself in the lawsuit.

Texas-Ohio Energy, Inc. vs. Centerpoint Energy, et al. On Nov. 19, 2003, a class action complaint filed in the U.S. District Court for the Eastern District of California by Texas-Ohio Energy, Inc. was served on the Xcel Energy naming e prime as a defendant. The lawsuit, filed on behalf of a purported class of large wholesale natural gas purchasers, alleges that e prime falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California. The case has been conditionally transferred to U.S. District Judge Pro in Nevada who is supervising western areas wholesale natural gas marketing litigation. A motion is currently pending to transfer the case back to the Eastern District of California. e prime has not yet responded to the complaint. The case is in the early stages, there has been no discovery, and Xcel Energy intends to vigorously defend against these claims.

Other Contingencies

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, borrowings have been made against the cash values of these COLI policies and the interest expense on these borrowings has been deducted. 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, the IRS examination division has disallowed 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 these reasons, 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 U.S. 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 2003 are estimated to total approximately $404 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2003, would reduce earnings by an estimated $254 million after tax.

18. 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 2003, $13 million in 2002 and $11 million in 2001. In total, NSP-Minnesota had paid approximately $321 million to the DOE through Dec. 31, 2003. However, it is not determinable 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, which consist of storage pools and a dry cask facility. With the dry cask storage facility licensed by the NRC approved in 1994 and again in 2003, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least the end of its license terms in 2013 and 2014. The Monticello nuclear plant has storage capacity in the pool to continue operations until 2010. Storage availability to permit operation beyond these dates is not known at this time. All of the alternatives for spent-fuel storage are being investigated 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.

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 2003 was $4.5 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, the unamortized assessment of $16.8 million at Dec. 31, 2003, is deferred as a regulatory asset.

Plant Decommissioning Decommissioning of NSP-Minnesota's nuclear facilities is planned for the years 2010 through 2048, using the prompt dismantlement method. NSP-Minnesota is currently following industry practice by accruing the costs for decommissioning over the approved cost-recovery period and including the accruals in Accumulated Depreciation. Upon implementation of SFAS No. 143, the decommissioning costs in Accumulated Depreciation and ongoing accruals are reclassified to a regulatory liability account. The total decommissioning cost obligation is recorded as an asset retirement obligation in accordance with SFAS No. 143. See Accounting Change – SFAS No. 143 for additional information.

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. In 2003, the Minnesota Legislature changed a law that had limited expansion of on-site storage. NSP-Minnesota will make a decision on whether to pursue license renewal for the Monticello and Prairie Island plants. Applications for license renewal must be submitted to the 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. NSP-Minnesota'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.

Consistent with cost recovery in utility customer rates, NSP-Minnesota records 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 4.19 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 December 2003, using 2002 cost data. An original filing was submitted to the MPUC in October 2002 and updated in August 2003; final approval was received in December 2003. The most recent cost estimate represents an annual increase in external fund accruals, along with the extension of Prairie Island cost recovery to the end of license life in 2014. The MPUC also approved the Department of Commerce recommendation to accelerate the internal fund transfer to the external funds effective July 1, 2003, ending on Dec. 31, 2005. These approvals increased the fund cash contribution by approximately $29 million in 2003, but may not have a statement of operations impact. Expecting to operate Prairie Island through the end of each unit's licensed life, the approved capital recovery will allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2014. Xcel Energy believes 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, 2003, 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. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

At Dec. 31, 2003, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $722 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation at Dec. 31, 2003:

(Thousands of dollars)	*2003*
Estimated decommissioning cost obligation from most recently approved study (2002 dollars)	**$1,716,618**
Effect of escalating costs to 2003 dollars (at 4.19 percent per year)	**71,926**
Estimated decommissioning cost obligation in current dollars	**1,788,544**
Effect of escalating costs to payment date (at 4.19 percent per year)	**2,004,821**
Estimated future decommissioning costs (undiscounted)	**3,793,365**
Effect of discounting obligation (using risk-free interest rate)	**(2,274,469)**
Discounted decommissioning cost obligation	**1,518,896**
Assets held in external decommissioning trust	**779,382**
Discounted decommissioning obligation in excess of assets currently held in external trust	**$ 739,514**

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	*2003*	*2002*	*2001*
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	**$80,582**	$51,433	$51,433
Internally funded (including interest costs)	**(35,906)**	(18,797)	(17,396)
Interest cost on externally funded decommissioning obligation	**(14,952)**	(32)	4,535
Earnings (losses) from external trust funds	**14,952**	32	(4,535)
Net decommissioning accruals recorded	**$44,676**	$32,636	$34,037

Decommissioning and interest accruals are included with Regulatory Liabilities on the Consolidated Balance Sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the Consolidated Statement of Operations.

Negative accruals for internally funded portions in 2001, 2002 and 2003 reflect the impacts of the 1999 and 2002 decommissioning studies, which have 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.

Accounting Change – SFAS No. 143 Xcel Energy adopted Statement of Financial Accounting Standard (SFAS) No. 143 – "Accounting for Asset Retirement Obligations" effective Jan. 1, 2003. As required by SFAS No. 143, future plant decommissioning obligations were recorded as a liability at fair value as of Jan. 1, 2003, with a corresponding increase to the carrying values of the related long-lived assets. This liability will be increased over time by applying the interest method of accretion to the liability, and the capitalized costs will be depreciated over the useful life of the related long-lived assets.

The impact of the adoption of SFAS No. 143 for Xcel Energy's utility subsidiaries is described later. The adoption had no income statement impact due to the deferral of the cumulative effect adjustments required under SFAS No. 143, through the establishment of a regulatory asset pursuant to SFAS No. 71.

Asset retirement obligations were recorded for the decommissioning of two NSP-Minnesota nuclear generating plants, the Monticello plant and the Prairie Island plant. A liability was also recorded for the decommissioning of an NSP-Minnesota steam production plant, the Pathfinder plant. 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. Pathfinder operated as a steam production peaking facility from 1969 until its retirement.

A summary of the accounting for the initial adoption of SFAS No. 143, as of Jan. 1, 2003, is as follows:

(Thousands of dollars)	*Increase (decrease) in:* Plant Assets	Regulatory Assets	Long-Term Liabilities
Reflect retirement obligation when liability incurred	$130,659	$ –	$130,659
Record accretion of liability to adoption date	–	731,709	731,709
Record depreciation of plant to adoption date	(110,573)	110,573	–
Recharacterize previously recorded decommissioning accruals	–	(662,411)	(662,411)
Net impact of SFAS No. 143 on balance sheet	$ 20,086	$179,871	$199,957

A reconciliation of the beginning and ending aggregate carrying amounts of NSP-Minnesota's asset retirement obligations recorded under SFAS No. 143 are shown in the table below for the 12 months ended Dec. 31, 2003:

(Thousands of dollars)	*Beginning Balance Jan. 1, 2003*	*Liabilities Incurred*	*Liabilities Settled*	*Accretion*	*Revisions to Prior Estimates*	***Ending Balance Dec. 31, 2003***
Steam plant retirement	$ 2,725	$ –	$ –	$ 135	$ –	**$ 2,860**
Nuclear plant decommissioning	859,643	–	–	58,341	103,685	**1,021,669**
Total liability	$862,368	$ –	$ –	$58,476	$103,685	**$1,024,529**

The adoption of SFAS No. 143 resulted in the recording of a capitalized plant asset of $131 million for the discounted cost of asset retirement as of the date the liability was incurred. Accumulated depreciation on this additional capitalized cost through the date of adoption of SFAS No. 143 was $111 million. A regulatory asset of $842 million was recognized for the accumulated SFAS No. 143 costs for accretion of the initial liability and depreciation of the additional capitalized cost through adoption date. This regulatory asset was partially offset by $662 million for the reversal of the decommissioning costs previously accrued for these plants prior to the implementation of SFAS No. 143. The net regulatory asset of $180 million at Jan. 1, 2003, reflects the excess of costs that would have been recorded in expense under SFAS No. 143 over the amount of costs recorded consistent with ratemaking cost recovery for NSP-Minnesota. This regulatory asset is expected to reverse over time since the costs to be accrued under SFAS No. 143 are expected to be the same as the costs to be recovered through current NSP-Minnesota ratemaking. Consequently, no cumulative effect adjustment to earnings or shareholders' equity has been recorded for the adoption of SFAS No. 143 in 2003, as all such effects have been deferred as a regulatory asset.

In August 2003, prior estimates for the nuclear plant decommissioning obligations were revised to incorporate the assumptions made in NSP-Minnesota's updated 2002 nuclear decommissioning filing with the MPUC. The revised estimates resulted in an increase of $104 million to both the regulatory asset and the long-term liability, as discussed previously. The revised estimates reflected changes in cost estimates due to changes in the escalation factor, changes in the estimated start date for decommissioning and changes in assumptions for storage of spent nuclear fuel. The changes in assumptions for the estimated start date for decommissioning and changes in the assumptions for storage of spent nuclear fuel are a result of recent Minnesota legislation that authorized additional spent nuclear fuel storage.

The pro forma liability to reflect amounts as if SFAS No. 143 had been applied as of Dec. 31, 2002, was $862 million, the same as the Jan. 1, 2003, amounts discussed previously. The pro forma liability to reflect adoption of SFAS No. 143 as of Jan. 1, 2002, the beginning of the earliest period presented, was $810 million.

Pro forma net income and earnings per share have not been presented for the year ended Dec. 31, 2002, because the pro forma application of SFAS No. 143 to prior periods would not have changed net income or earnings per share of Xcel Energy or NSP-Minnesota due to the regulatory deferral of any differences of past cost recognition and SFAS No. 143 methodology, as discussed previously.

The fair value of NSP-Minnesota assets legally restricted for purposes of settling the nuclear asset retirement obligations is $900 million as of Dec. 31, 2003, including external nuclear decommissioning investment funds and internally funded amounts.

Removal Costs The adoption of SFAS No. 143 in 2003 also affects 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 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, the utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accordingly, the recorded amounts of estimated future removal costs are considered Regulatory Liabilities under SFAS No. 71. Removal costs by entity are as follows at Dec. 31:

(Millions of dollars)	*2003*	*2002*
NSP-Minnesota	**$324**	$304
NSP-Wisconsin	**75**	70
PSCo	**351**	329
SPS	**102**	97
Cheyenne Light, Fuel & Power Co.	**10**	10
Total Xcel Energy	**$862**	$810

19. REGULATORY ASSETS AND LIABILITIES

Xcel Energy's 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 to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot use SFAS No. 71 accounting. The components of unamortized regulatory assets and liabilities of continuing operations shown on the balance sheet at Dec. 31 were:

(Thousands of dollars)	*See Note*	*Remaining Amortization Period*	*2003*	*2002*
Regulatory Assets				
Net nuclear asset retirement obligations	1, 18	End of licensed life	**$ 186,989**	$ –
Power purchase contract valuation adjustments	16	Term of related contract	**154,260**	–
AFDC recorded in plant *(a)*		Plant lives	**153,491**	154,158
Losses on reacquired debt	1	Term of related debt	**101,616**	85,888
Conservation programs *(a)*		Five to 10 years	**76,087**	53,860
Nuclear decommissioning costs *(b)*		Up to four years	**37,654**	53,567
Employees' postretirement benefits other than pension	12	Nine years	**35,015**	38,899
Renewable resource costs		To be determined	**25,972**	26,000
Environmental costs	17, 18	To be determined	**29,195**	30,974
State commission accounting adjustments *(a)*		Plant lives	**17,301**	19,157
Plant asset recovery (Pawnee II and Metro Ash)		Four years	**17,162**	–
Unrecovered natural gas costs *(c)*	1	One to two years	**16,008**	12,296
Unrecovered electric production costs *(d)*	1	15 months	**13,779**	67,709
Other		Various	**15,311**	15,630
Deferred income tax adjustments	1	Mainly plant lives	**–**	18,738
Total regulatory assets			**$ 879,840**	$ 576,876
Regulatory Liabilities				
Plant removal costs	1, 18		**$ 862,406**	$ 810,184
Pension costs – regulatory differences	12		**338,926**	287,615
Power purchase contract valuation adjustments	16		**126,884**	–
Unrealized gains from decommissioning investments	18		**105,518**	112,145
Investment tax credit deferrals			**101,073**	109,571
Deferred income tax adjustments	1		**25,906**	–
Interest on income tax refunds			**7,369**	6,569
Fuel costs, refunds and other			**2,466**	2,527
Total regulatory liabilities			**$1,570,548**	$1,328,611

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

(b) 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.

(c) Excludes current portion expected to be returned to customers within 12 months of $3.1 million for 2003, and the 2002 current portion expected to be recovered from customers of $12.1 million.

(d) Excludes current portion expected to be recovered within the next 12 months of $55.8 and $54.2 million for 2003 and 2002, respectively.

20. SEGMENTS AND RELATED INFORMATION

Xcel Energy has the following reportable segments: Regulated Electric Utility, Regulated Natural Gas Utility and All Other.

- Xcel Energy's Regulated Electric Utility segment 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. Regulated Electric Utility also includes electric trading.
- Xcel Energy's Regulated Natural Gas Utility segment transports, stores and distributes natural gas and propane primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan, Colorado and Wyoming.

To report income from continuing operations for Regulated Electric and Regulated 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.

(Thousands of dollars)	*Regulated Electric Utility*	*Regulated Natural Gas Utility*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
2003					
Operating revenues from external customers	**$5,969,356**	**$1,710,272**	**$ 257,888**	**$ –**	**$7,937,516**
Intersegment revenues	**1,123**	**10,868**	**53,866**	**(65,857)**	**–**
Total revenues	**$5,970,479**	**$1,721,140**	**$ 311,754**	**$ (65,857)**	**$7,937,516**
Depreciation and amortization	**$ 628,108**	**$ 81,794**	**$ 46,098**	**$ –**	**$ 756,000**
Financing costs, mainly interest expense	**313,456**	**58,259**	**104,022**	**(23,435)**	**452,302**
Income tax expense (benefit)	**240,186**	**31,928**	**(113,472)**	**–**	**158,642**
Income (loss) from continuing operations	**$ 462,528**	**$ 94,873**	**$ (10,142)**	**$ (37,239)**	**$ 510,020**
2002					
Operating revenues from external customers	$5,437,017	$1,363,359	$ 234,749	$ –	$7,035,125
Intersegment revenues	987	5,396	94,304	(100,684)	3
Total revenues	$5,438,004	$1,368,755	$ 329,053	$ (100,684)	$7,035,128
Depreciation and amortization	$ 649,020	$ 87,259	$ 34,986	$ –	$ 771,265
Financing costs, mainly interest expense	286,872	49,075	125,667	(39,207)	422,407
Income tax expense (benefit)	297,420	44,789	(106,595)	–	235,614
Income (loss) from continuing operations	$ 486,811	$ 89,026	$ (2,067)	$ (46,077)	$ 527,693
2001					
Operating revenues from external customers	$6,463,411	$2,020,530	$ 236,846	$ –	$8,720,787
Intersegment revenues	1,189	9,932	85,891	(93,772)	3,240
Total revenues	$6,464,600	$2,030,462	$ 322,737	$ (93,772)	$8,724,027
Depreciation and amortization	$ 616,283	$ 87,906	$ 22,606	$ –	$ 726,795
Financing costs, mainly interest expense	265,999	45,723	101,318	(46,604)	366,436
Income tax expense (benefit)	343,488	39,509	(78,655)	–	304,342
Income (loss) from continuing operations	$ 555,976	$ 63,051	$ 4,813	$ (44,640)	$ 579,200

In 2003, the process to allocate common costs of the Regulated Electric and Natural Gas Utility segments was revised. Segment results for 2002 and 2001 have been restated to reflect the revised cost allocation process.

Prior to its divestiture in 2003, NRG was previously considered a reportable segment of Xcel Energy. NRG is now reported as a discontinued operation, as discussed in Note 3 to the Consolidated Financial Statements. See Note 3 for summarized financial information regarding NRG.

21. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly unaudited financial data is as follows:

(Thousands of dollars, except per share amounts)	*Quarter ended* March 31, 2003 (a)	June 30, 2003 (a)	Sept. 30, 2003 (a)	Dec. 31, 2003 (a)
Revenue	**$2,086,107**	**$1,721,754**	**$2,019,853**	**$2,109,802**
Operating income (loss)	**304,022**	**162,624**	**358,658**	**259,943**
Income (loss) from continuing operations	**126,778**	**54,982**	**180,039**	**148,221**
Discontinued operations – income (loss)	**13,234**	**(337,544)**	**107,456**	**329,226**
Net income (loss)	**140,012**	**(282,562)**	**287,495**	**477,447**
Earnings (loss) available for common shareholders	**138,952**	**(283,622)**	**286,435**	**476,386**
Earnings (loss) per share from continuing operations – basic	**$ 0.32**	**$ 0.14**	**$ 0.45**	**$ 0.37**
Earnings (loss) per share from continuing operations – diluted	**$ 0.31**	**$ 0.14**	**$ 0.43**	**$ 0.36**
Earnings (loss) per share from discontinued operations – basic	**$ 0.03**	**$ (0.85)**	**$ 0.27**	**$ 0.83**
Earnings (loss) per share from discontinued operations – diluted	**$ 0.03**	**$ (0.85)**	**$ 0.26**	**$ 0.78**
Earnings (loss) per share total – basic	**$ 0.35**	**$ (0.71)**	**$ 0.72**	**$ 1.20**
Earnings (loss) per share total – diluted	**$ 0.34**	**$ (0.71)**	**$ 0.69**	**$ 1.14**

(Thousands of dollars, except per share amounts)	*Quarter ended* March 31, 2002 (b)	June 30, 2002 (b)	Sept. 30, 2002 (b)	Dec. 31, 2002 (b)
Revenue	$1,834,811	$1,598,832	$1,726,436	$1,875,049
Operating income (loss)	253,498	262,513	373,188	251,838
Income (loss) from continuing operations	121,578	117,242	178,002	110,871
Discontinued operations – income (loss)	(18,074)	(29,940)	(2,382,042)	(315,628)
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	$ 0.34	$ 0.31	$ 0.44	$ 0.27
Earnings (loss) per share from continuing operations – diluted	$ 0.34	$ 0.31	$ 0.44	$ 0.27
Earnings (loss) per share from discontinued operations – basic	$ (0.05)	$ (0.08)	$ (5.99)	$ (0.79)
Earnings (loss) per share from discontinued operations – diluted	$ (0.05)	$ (0.08)	$ (5.99)	$ (0.77)
Earnings (loss) per share total – basic	$ 0.29	$ 0.23	$ (5.55)	$ (0.52)
Earnings (loss) per share total – diluted	$ 0.29	$ 0.23	$ (5.55)	$ (0.50)

(a) 2003 results include special charges in certain quarters, as discussed in Note 2 to the Consolidated Financial Statements, and unusual items as follows:

- *Results from continuing operations were decreased for NRG-related restructuring costs incurred by the holding company in the amount of $1.4 million in the first quarter, $7.3 million in the second quarter, and $3.0 million in the third quarter.*
- *Fourth-quarter results from continuing operations were increased by $22 million, or 3 cents per share, for adjustments made to depreciation accruals for the year, due to a regulatory decision approving the extension of NSP-Minnesota's Prairie Island nuclear plant to operate over the license term.*
- *Fourth-quarter results from continuing operations were increased by $30 million, or 7 cents per share, for adjustments made to income tax accruals to reflect the successful resolution of various outstanding tax issues.*
- *Fourth-quarter results from continuing operations were decreased by $7 million pretax, or 1 cent per share, for charges recorded related to the TRANSLink project due to regulatory and operating uncertainties.*
- *Fourth-quarter results from discontinued operations were increased by $111 million, or 26 cents per share, for reversal of equity in prior NRG losses due to the divestiture of NRG in December 2003, and increased by $288 million, or 68 cents per share, due to revisions to the estimated tax benefits related to Xcel Energy's investment in NRG. See Note 3 to the Consolidated Financial Statements for further discussion of these items.*
- *Fourth-quarter results from discontinued operations were decreased by $59 million, or 14 cents per share, due to the estimated impairment expected to result from the disposal of Xcel Energy International's Argentina assets, as discussed in Note 3 to the Consolidated Financial Statements, and by $16 million, or 4 cents per share, due to the accrual of e prime's cost to settle an investigation by the Commodity Futures Trading Commission.*

(b) 2002 results include special charges in certain quarters, as discussed in Note 2 to the Consolidated Financial Statements, and unusual items as follows:

- *First-quarter results from continuing operations 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 included in special charges.*
- *Results from continuing operations were decreased in the amount of $1.2 million in the third quarter and $3.6 million in the fourth quarter for NRG-related restructuring costs incurred by the holding company.*
- *Fourth-quarter results from discontinued operations were decreased by $95 million, or 23 cents per share, for NRG charges related to asset impairments and financial restructuring costs, and increased by $30 million, or 7 cents per share, due to revisions to the estimated tax benefits related to Xcel Energy's investment in NRG.*

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This is an automated phone system to expedite requests. However, staying on the line to speak with a representative is an option. Representatives are available from 7 a.m. to 7 p.m. CST.

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Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at www.xcelenergy.com.

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Common stock is listed on the New York, Chicago and Pacific exchanges under the ticker symbol XEL. The New York Stock Exchange lists some of Xcel Energy's preferred stock. In newspaper listings, it appears as XcelEngy.

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* *Wayne H. Brunetti is an ex officio member of all committees.*

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