XCEL ENERGY INC
Form 424B3
November 17, 2003

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Filed Pursuant To Rule 424B(3)
Registration No. 333-109601

Xcel Energy Inc.

Offer to Exchange

$195,000,000 3.40% Senior Notes, Series B due 2008
For Any and All Outstanding
$195,000,000 3.40% Senior Notes, Series A due 2008

The Exchange Offer will expire at 5:00 p.m., New York City time, on December 19, 2003, unless extended.

Terms of the Exchange Offer

We are offering to exchange senior notes registered under the Securities Act of 1933, as amended, for a like principal amount of original senior notes that we issued in a private placement that closed on June 24, 2003.

The terms of the exchange senior notes are substantially identical to the terms of the original senior notes, except that the exchange senior notes will not contain transfer restrictions and will not have the registration rights that apply to the original senior notes or entitle their holders to additional interest in the event we fail to comply with these registration rights. The terms and conditions of the exchange offer are more fully described in this prospectus.

Wells Fargo Bank Minnesota, National Association is serving as the exchange agent. If you wish to tender your original senior notes, you must complete, execute and deliver, among other things, a letter of transmittal to the exchange agent no later than 5:00 p.m., New York City time, on the expiration date.

You may withdraw tenders of original senior notes at any time prior to the expiration of the exchange offer. We will exchange all original senior notes that are validly tendered and not withdrawn prior to the expiration of the exchange offer.

Any outstanding original senior notes not validly tendered will remain subject to existing transfer restrictions.

There is no existing market for the exchange senior notes offered by this prospectus and we do not intend to apply for their listing on any securities exchange or any automated quotation system.

We believe that the exchange of original senior notes for exchange senior notes will not be taxable for United States federal income tax purposes. See Material United States Federal Income Tax Considerations.

The exchange senior notes will have the same terms and covenants as the original senior notes, and will be subject to the same business and financial risks.

You should consider carefully the Risk Factors beginning on page 14 of this prospectus before tendering your original senior notes for exchange.

We are not asking you for a proxy and you are requested not to send us a proxy.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus is dated November 14, 2003.

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You should rely only on the information provided in this prospectus. We have not authorized anyone else to provide you with different information. This prospectus does not constitute an offer of these securities in any state where the offer is not permitted. You should not assume that the information in this prospectus is accurate as of any date other than the date on the front of this prospectus.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that are not historical fact and constitute forward-looking statements. When we use words like believes, expects, anticipates, intends, plans, estimates, may, should, objective, outlook, projected, possible, potential or similar e discuss our strategy or plans, we are making forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Our future results may differ materially from those expressed in these forward-looking statements. These statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others:

general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures and our ability and the ability of our subsidiaries to obtain financing on favorable terms;

business conditions in the retail and wholesale energy industry;

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- competitive factors, including the extent and timing of the entry of additional competition in the markets served by us and our subsidiaries;
- unusual weather;
- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates structures and affect the speed and degree to which competition enters the electric and gas markets;
- the higher risk associated with our nonregulated businesses compared with our regulated businesses;
- currency translation and transaction adjustments;
- risks associated with the California power market;
- risks related to the financial condition of NRG Energy, Inc. and actions taken by the bankruptcy court in NRG s bankruptcy proceeding;
- costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including without limitation claims brought against us by creditors, shareholders or others relating to our ownership of NRG;
- failure to realize expectations regarding the NRG settlement agreement discussed elsewhere in this prospectus;
- the effect on the U.S. economy as a consequence of war and acts of terrorism; and
- the other risk factors discussed under Risk Factors.

You are cautioned not to rely unduly on any forward-looking statements. These risks and uncertainties are discussed in more detail under Risk Factors, Business and Management s Discussion and Analysis of Financial Condition and Results of Operations, and the notes to the audited consolidated financial statements and interim consolidated financial statements included in this prospectus.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.

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SUMMARY

This summary highlights some of the information contained elsewhere in this prospectus. Because this is only a summary, it does not contain all of the information that may be important to you. For a more complete understanding of this exchange offer, we encourage you to read this entire prospectus and the documents to which we refer you in deciding whether to exchange your original senior notes for exchange senior notes. The term original senior notes as used in this prospectus refers to our outstanding 3.40% senior notes, series A due 2008 that we issued on June 24, 2003 and that have not been registered under the Securities Act of 1933, as amended (the Securities Act). The term exchange senior notes refers to our 3.40% senior notes, series B due 2008 offered under this prospectus.

In this prospectus, except as otherwise indicated or as the context otherwise requires, Xcel Energy, we, our, and us refer to Xcel Energy Inc., a Minnesota corporation. In the discussion of our business in this prospectus, we, our and us refers also to our subsidiaries.

Our Company

General

We are a public utility holding company with five utility subsidiaries:

Northern States Power Company, a Minnesota corporation (NSP-Minnesota), which serves approximately 1.3 million electric customers and approximately 430,000 gas customers in Minnesota, North Dakota and South Dakota;

Public Service Company of Colorado, a Colorado corporation (PSCo), which serves approximately 1.3 million electric customers and approximately 1.2 million gas customers in Colorado;

Southwestern Public Service Company, a New Mexico corporation (SPS), which serves approximately 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas;

Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), which serves approximately 230,000 electric customers and approximately 90,000 gas customers in northern Wisconsin and Michigan; and

Cheyenne Light, Fuel and Power Company, a Wyoming corporation, which serves approximately 37,000 electric customers and approximately 30,000 gas customers in and around Cheyenne, Wyoming.

Our regulated businesses also include WestGas InterState Inc., an interstate natural gas pipeline company. Prior to January 2003, our regulated businesses included Viking Gas Transmission Company. As discussed below, on October 20, 2003, we completed the sale of Black Mountain Gas Company, an Arizona corporation (BMG), which serves approximately 8,500 natural gas customers and 2,500 propane customers in Arizona.

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. (NRG). NRG is a global energy company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products. As discussed in more detail below, on May 14, 2003, NRG and some of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As discussed below, we have reached a tentative settlement with NRG and some of NRG s creditors. If the bankruptcy court approves the terms of this settlement, we will divest our ownership interest in NRG when NRG emerges from bankruptcy.

In addition to NRG, our nonregulated subsidiaries include:

Utility Engineering Corporation, which is involved in engineering, construction and design;

Seren Innovations, Inc., which is involved in broadband telecommunications services;

e prime, Inc. (e prime), which is involved in natural gas marketing and trading;

Planergy International Inc., which is involved in energy management consulting and demand-side management services;

Eloigne Company, which is involved in the ownership of rental housing projects that qualify for low-income housing tax credits; and

Xcel Energy International Inc., an international independent power producer.

We were incorporated in 1909 under the laws of Minnesota as Northern States Power Company. On August 18, 2000, we merged with New Century Energies, Inc. and our name was changed from Northern States Power Company to Xcel Energy Inc.

Our principal executive offices are located at 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota 55402, and our telephone number at that location is (612) 330-5500.

Regulatory Overview

We are registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). As a result, we, our utility subsidiaries and certain of our non-utility subsidiaries are subject to extensive regulation by the Securities and Exchange Commission (SEC) under PUHCA, including, among other things, our issuances and sales of securities, capital structure, acquisitions and sales of certain utility properties and intra-system sales of certain goods and services. In addition, 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.

The electric and natural gas rates charged to customers of our utility subsidiaries are approved by the Federal Energy Regulatory Commission (the FERC) or the utility 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. We request changes in rates for utility services through filings with the regulatory commissions. Because comprehensive rate changes are requested infrequently in some states, changes in operating costs can affect our 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 costs of capital.

Recent Developments

NRG Bankruptcy

Since mid-2002, NRG has experienced severe financial difficulties, resulting primarily from lower prices for power and declining credit ratings. These financial difficulties have caused NRG to, among other things, fail to make payments of interest and/or principal aggregating over $400 million on outstanding indebtedness of over $4 billion and incur asset impairment charges and other costs in excess of $3 billion for the year ended December 31, 2002. These asset impairment charges include write-offs for anticipated losses on sales of several NRG projects as well as anticipated losses related to projects for which NRG has stopped funding. Given the changing business conditions for NRG and the resolution of its plan of reorganization discussed below, additional significant asset impairments may be recorded by NRG.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the support and capital subscription agreement between us and

NRG dated May 29, 2002 (the Support Agreement). The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement are as follows:

We would pay up to $752 million to NRG to settle claims of NRG against us, including all claims under the Support Agreement, and claims of NRG creditors who release us under the NRG plan of reorganization described below.

$350 million (including $112 million payable to NRG s bank lenders) would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made in early 2004.

$50 million would be paid in early 2004, and all or any part of such payment could be made, at our election, in our common stock.

Up to $352 million would be paid commencing on April 30, 2004, unless at such time we had not received tax refunds equal to at least $352 million associated with the loss on our investment in NRG. To the extent such refunds are less than the required payments, the difference between the required payments and those refunds will be due on May 30, 2004.

$390 million of the up to $752 million of total payments are contingent on receiving releases from NRG creditors. To the extent we are not released by an NRG creditor, our obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon us receiving voluntary releases from at least 85 percent of the unsecured claims held by NRG creditors (including releases from 100 percent of NRG s bank creditors). As a result, it is not expected that our payment obligations would be reduced by more than approximately $60 million. Any reduction would come from our payments becoming due commencing on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guaranties or indemnities or other credit support obligations incurred by us for the benefit of NRG or any of NRG s subsidiaries would be terminated or other arrangements would be made such that we have no further liability and any cash collateral posted by us would be returned. As of September 30, 2003, the maximum amount stated in our guarantees of obligations of NRG and its subsidiaries was approximately $80 million and our actual aggregate exposure on guarantees of obligations of NRG and its subsidiaries as of September 30, 2003 was approximately $5 million, which amount will vary over time. As of September 30, 2003, we had provided indemnities to sureties in respect of bonds for the benefit of NRG and its subsidiaries in an aggregate amount of approximately $6 million. As of October 31, 2003, no cash collateral was posted.

As part of the settlement with us, any intercompany claims we have against NRG or any subsidiary arising from the provision of goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of January 31, 2003 will be reduced to $10 million. The $10 million agreed amount is to be satisfied upon the effective date of the NRG plan of reorganization, with an unsecured promissory note of NRG in the principal amount of $10 million and with a maturity of 30 months and an annual interest rate of 3 percent.

NRG and its subsidiaries would not be reconsolidated with us or any of our other affiliates for tax purposes at any time after their March 2001 deconsolidation (except to the extent required by state and local tax law) or treated as party to or otherwise entitled to the benefits of any existing tax sharing agreement with us. However, NRG and certain subsidiaries would continue to be treated as they were under our December 2000 tax allocation agreement to the extent they remain part of a consolidated or combined state tax group that includes us. Under the settlement, NRG would not be entitled to any tax benefits associated with the tax loss we expect to recognize as a result of the cancellation of our stock in NRG on the effective date of the NRG plan of reorganization.

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Commencing on May 14, 2003, NRG and certain of NRG s affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement (based on the settlement discussed above) among us, NRG and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

A plan support agreement reflecting the settlement has been signed by us, NRG, a holder of approximately 40 percent in principal amount of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. The terms of the plan support agreement with NRG s major creditors are basically the same as the March 26, 2003 tentative settlement discussed above. This agreement will become effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and specified other noteholders and bondholders and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. At this time, it appears unlikely that the plan support agreement will receive the requisite signatures prior to the effective date of the reorganization. However it is expected that various settlement-related agreements incorporating the terms of the settlement, which will be exhibits or supplements to the plan of reorganization and would be subject to approval in connection with the confirmation of the plan of reorganization, would supercede the plan support agreement. If approved, these agreements would be expected to be executed when the plan of reorganization is confirmed.

Consummation of the overall settlement, including our obligations to make the payments set forth above, is contingent upon, among other things, the following:

The effective date of the NRG plan of reorganization for the NRG voluntary bankruptcy proceeding occurring on or prior to December 15, 2003;

The final plan of reorganization approved by the bankruptcy court and related documents containing terms satisfactory to us, NRG and various groups of the NRG creditors;

The receipt of releases in our favor from holders of at least 85 percent of the unsecured claims held by NRG s creditors (including releases from 100 percent of NRG s bank creditors); and

Our receipt of all necessary regulatory and other approvals.

On July 22, 2003, we and NRG submitted a joint application to the FERC requesting approval for us to dispose of our interest in NRG by implementing the proposed plan of reorganization filed in the NRG bankruptcy proceeding. On October 8, 2003, the FERC issued an order approving the application.

On July 28, 2003, we and NRG submitted an application to the SEC under PUHCA seeking authorization under the Act to perform those acts and consummate those transactions contemplated as part of NRG s proposed plan of reorganization. On October 10, 2003, the SEC issued an order approving the application.

On October 14, 2003, the solicitation for approval of NRG s plan of reorganization commenced. On November 12, 2003, votes on the plan of reorganization and objections to the plan of reorganization were due. Confirmation hearings on NRG s plan of reorganization have been scheduled for November 21, 2003 and November 24, 2003. Appeals to the NRG plan of reorganization must be filed within ten days after the confirmation of NRG s plan of reorganization.

Since many of these conditions to the effectiveness of the NRG plan of reorganization and the consummation of the settlement are not within our control, we cannot state with certainty that NRG s plan of reorganization, in the form filed with the bankruptcy court, will be confirmed or that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented. Our management also believes that any effort to substantively consolidate Xcel Energy s assets and liabilities with those of NRG during the bankruptcy proceedings would be without merit.

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Sale of Black Mountain Gas Company

On October 20, 2003, we completed the sale of BMG to Southwest Gas Corporation of Las Vegas, Nevada. BMG is a natural gas and propane distribution company serving natural gas customers in Cave Creek, Carefree, North Phoenix and North Scottsdale, Arizona and propane customers in the Page, Arizona and Cave Creek areas.

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Summary of the Exchange Offer

On June 24, 2003, we completed the private offering of $195 million in aggregate principal amount of our 3.40% senior notes, series A due 2008. These original senior notes were not registered under the Securities Act and, therefore, they are subject to significant restrictions on resale. Accordingly, when we sold these original senior notes, we entered into a registration rights agreement with the initial purchasers that requires us to deliver to you this prospectus and to permit you to exchange your original senior notes for exchange senior notes that have substantially identical terms to the original senior notes, except that the exchange senior notes will be freely transferable and will not have covenants regarding registration rights or additional interest. The exchange senior notes will be issued under the same indenture under which the original senior notes were issued and, as a holder of the exchange senior notes, you will be entitled to the same rights under the indenture that you had as a holder of original senior notes.

Set forth below is a summary description of the terms of the exchange offer.

Exchange Offer	We are offering to exchange up to $195 million in aggregate principal amount of exchange senior notes for a like aggregate principal amount of original senior notes. Original senior notes may be tendered only in increments of $1,000.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on December 19, 2003, unless we extend it. We do not currently intend to extend the exchange offer.
Interest on the Exchange Senior Notes	Interest on the exchange senior notes will accrue at the rate of 3.40% from the date of the last periodic payment of interest on the original senior notes or, if no interest has been paid, from June 24, 2003.
Conditions to the Exchange Offer	The exchange offer is subject to customary conditions, including that:
	there is no change in law, regulation or any applicable interpretation of the SEC staff that prevents us from proceeding with the exchange offer;
	there is no action or proceeding, pending or threatened, that would impair our ability to proceed with the exchange offer;
	no stop order has been issued by the SEC or any state securities authority suspending the effectiveness of the registration statement of which this prospectus is a part;
	all government approvals necessary for the consummation of the exchange offer have been obtained; and
	no change in our business or financial affairs has occurred that might materially impair our ability to proceed with the exchange offer.
Procedure for Exchanging Original Senior Notes	If the original senior notes you wish to exchange are registered in your name:
	you must complete, sign and date the letter of transmittal and mail or otherwise deliver it, together with any other required documentation, to Wells Fargo Bank Minnesota, National Asso-

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	ciation, as exchange agent, at the address specified on the cover page of the letter of transmittal.
	If the original senior notes you wish to exchange are in book-entry form and registered in the name of a broker, dealer or other nominee:
	you must contact the broker, dealer, commercial bank, trust company or other nominee in whose name your original senior notes are registered and instruct it to tender your original senior notes on your behalf. You must comply with the procedures of The Depository Trust Company (DTC) for tender and delivery of book-entry securities in order to validly tender your original senior notes for exchange.
	Questions regarding the exchange of original senior notes or the exchange offer generally should be directed to the exchange agent at the address specified under the caption The Exchange Offer Exchange Agent.
Guaranteed Delivery Procedures	If you wish to exchange your original senior notes and you cannot get the required documents to the exchange agent by the expiration date or you cannot tender and deliver your original senior notes in accordance with DTC s procedures by the expiration date, you may tender your original senior notes according to the guaranteed delivery procedures described under the caption The Exchange Offer Guaranteed Delivery Procedures.
Withdrawal Rights	You may withdraw the tender of your original senior notes at any time before 5:00 p.m., New York City time, on the expiration date of the exchange offer.
Acceptance of Original Senior Notes and Delivery of Exchange Senior Notes	We will accept for exchange any and all original senior notes that are properly tendered in the exchange offer before 5:00 p.m., New York City time, on the expiration date, as long as all of the terms and conditions of the exchange offer are met. We will deliver the exchange senior notes promptly following the expiration date.
Resale of Exchange Senior Notes	Based on interpretations by the staff of the SEC, as detailed in a series of no-action letters issued by the SEC to third parties, we believe that you may offer for resale, resell or otherwise transfer the exchange senior notes without complying with the registration and prospectus delivery requirements of the Securities Act if:
	you are acquiring the exchange senior notes in the ordinary course of your business and do not hold any original senior notes to be exchanged in the exchange offer that were acquired other than in the ordinary course of business;
	you are not a broker-dealer tendering original senior notes acquired directly from us;
	you are not participating, do not intend to participate and have no arrangements or understandings with any person to participate in the exchange offer for the purpose of distributing the exchange senior notes; and

	you are not our affiliate within the meaning of Rule 405 under the Securities Act.
	If any of these conditions is not satisfied and you transfer any exchange senior notes without delivering a proper prospectus or without qualifying for a registration exemption, you may incur liability under the Securities Act.
	Each broker or dealer that receives exchange senior notes for its own account in exchange for original senior notes that were acquired as a result of market-making or other trading activities must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of the exchange senior notes.
Consequences of Failure to Exchange	If you do not exchange your original senior notes for exchange senior notes, you will not be able to offer, sell or otherwise transfer the original senior notes except:
	in compliance with the registration requirements of the Securities Act and any other applicable securities laws;
	pursuant to an exemption from the securities laws; or
	in a transaction not subject to the securities laws.
	Original senior notes that remain outstanding after completion of the exchange offer will continue to bear a legend reflecting these restrictions on transfer. In addition, upon completion of the exchange offer, you will not be entitled to any rights to have the resale of original senior notes registered under the Securities Act (subject to limited exceptions applicable only to certain qualified institutional buyers). We currently do not intend to register under the Securities Act the resale of any original senior notes that remain outstanding after completion of the exchange offer.
	Upon completion of the exchange offer, there may be no market for the original senior notes, and if you fail to exchange the original senior notes, you may have difficulty selling them.
United States Federal Income Tax Considerations	Your acceptance of the exchange offer and the exchange of your original senior notes for exchange senior notes will not be taxable for U.S. federal income tax purposes. See Material United States Federal Income Tax Considerations beginning on page 179.
Exchange Agent	Wells Fargo Bank Minnesota, National Association is serving as exchange agent for the exchange offer.
Appraisal or Dissenter s Rights	You will have no appraisal or dissenters rights in connection with the exchange offer.

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Summary Description of the Exchange Senior Notes

The terms of the exchange senior notes we are issuing in the exchange offer and the original senior notes are identical in all material respects, except that:

- the exchange senior notes will have been registered under the Securities Act;
- the exchange senior notes will not contain transfer restrictions; and
- the exchange senior notes will not have the registration rights that apply to the original senior notes or entitle their holders to additional interest in the event we fail to comply with these registration rights.

A brief description of the material terms of the exchange senior notes is set forth below:

Securities Offered	$195,000,000 principal amount of 3.40% senior notes, series B due 2008.
Maturity	July 1, 2008.
Interest Rate	3.40% per annum.
Interest Payment Dates	January 1 and July 1 of each year, beginning on January 1, 2004.
Effect of Holding Company Structure	We are structured as a holding company and conduct substantially all of our business operations through our subsidiaries. The exchange senior notes will be effectively subordinated to all existing and future indebtedness and other liabilities and commitments of our subsidiaries. As of September 30, 2003, our subsidiaries had aggregate indebtedness and other liabilities of approximately $12.1 billion. This amount does not include indebtedness and other liabilities of our subsidiary, NRG, which was deconsolidated on our financial statements following its bankruptcy filing. See Selected Pro Forma Consolidated Financial Data.
Ranking	The exchange senior notes will be unsecured and unsubordinated obligations and will rank on a parity in right of payment with all our existing and future unsecured and unsubordinated indebtedness. The indenture under which the exchange senior notes will be issued will not prevent us or our subsidiaries from incurring additional indebtedness, which may be secured by some or all of our or their assets, as the case may be. As of September 30, 2003, we had approximately $1.025 billion of long-term debt outstanding, excluding long-term debt of our subsidiaries. There are currently no outstanding debt obligations junior to the exchange senior notes. See Description of Other Indebtedness.
Ratings	The exchange senior notes have been assigned a rating of BBB- (CreditWatch positive) by Standard & Poor s Ratings Services (Standard & Poor s) and Baa3 (stable outlook) by Moody s Investors Services, Inc. (Moody s). For a description of events affecting our credit ratings, see Risk Factors. Ratings from credit agencies are not recommendations to buy, sell or hold our securities and may be subject to revision or withdrawal at any time by the applicable rating agency and should be evaluated independently of any other ratings.
Optional Redemption	We may redeem the exchange senior notes at any time, in whole or in part, at a make whole redemption price equal to the greater of

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	(1) the principal amount being redeemed or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the exchange senior notes being redeemed, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Yield (as defined below under the caption Description of the Exchange Senior Notes) plus 25 basis points, plus in each case accrued and unpaid interest to the redemption date.
Use of Proceeds	We will not receive any proceeds from the issuance of the exchange senior notes. We are making the exchange offer solely to satisfy our obligations under the registration rights agreement that we entered into in connection with the private offering of the original senior notes.
Risk Factors	See Risk Factors and the other information in this prospectus for a discussion of factors you should carefully consider before deciding to exchange your original senior notes for exchange senior notes.

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Summary Historical Financial Data

The following tables present our summary consolidated historical financial data. The data presented in these tables are from Selected Consolidated Financial Data included elsewhere in this prospectus. You should read that section for a further explanation of the consolidated financial data summarized here. You should also read the summary consolidated financial data presented below in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited and unaudited consolidated financial statements and related notes and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Nine months ended September 30,		Year ended December 31,				
	2003	2002	2002(1)	2001	2000	1999	1998
			(Millions of dollars, except ratios)				
Consolidated Statement of Operations Data:							
Operating revenue	$5,975	$ 7,068	$ 9,524	$11,333	$9,223	$6,883	$6,606
Operating (loss) income	839	(1,529)	(1,433)	1,858	1,479	1,204	1,194
Interest charges and financing costs	343	585	918	767	653	453	383
Income (loss) from continuing operations	124	(1,447)	(1,661)	738	514	571	620
Net (loss) income	$ 145	$(2,013)	$(2,218)	$ 795	$ 527	$ 571	$ 624
Other Consolidated Financial Data							
Ratio of earnings to fixed charges(2)	2.2	(3)	(4)	2.0	1.9	2.4	3.0

	September 30, 2003(5)
	(Millions of dollars)
Consolidated Balance Sheet Data:	
Total assets	$18,264
Short-term debt (including current maturities)	$ 390
Long-term debt	$ 6,412
Total debt	$ 6,802
Minority interest	$ 5
Mandatorily redeemable preferred securities of subsidiary trusts(6)	$ 100
NRG losses in excess of investment	$ 927
Preferred stockholders equity	$ 104
Common stockholders equity	$ 4,714
Total capitalization (includes short-term debt and minority interests, but excludes NRG losses in excess of investment)	$11,725

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(1) Results for 2002 include two significant items which are described further in the notes to our consolidated financial statements: (a) impairment charges and disposal losses (excluding discontinued operations) related to NRG s long-lived assets and equity investments, which reduced operating income by $2.7 billion and net income by $2.6 billion; and (b) income tax benefits related to our investment in NRG which increased net income by $706 million.

(2) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of earnings from continuing operations plus fixed charges, federal and state income taxes, deferred income taxes and investment tax credits and less undistributed equity in earnings of unconsolidated investees, and (2) fixed charges consist of interest on long-term debt, other interest charges, distributions on redeemable preferred securities of subsidiary trusts and amortization of debt discount, premium and expense.

(3) Earnings as defined in the ratio for the nine months ended September 30, 2002 were reduced by NRG asset impairment charges of $2.5 billion. The fixed charges exceeded earnings, as defined in this ratio, by $2.1 billion for the nine months ended September 30, 2002.

(4) Earnings as defined in the ratio for the twelve months ended December 31, 2002 were reduced by NRG asset impairment charges of $2.5 billion. The fixed charges exceeded earnings, as defined for this ratio, by $2.3 billion in 2002.

(5) Individual asset and liability amounts exclude NRG amounts, which are reported under the equity method as a single current liability item, NRG Losses in Excess of Investment.

(6) On July 31, 2003, $200 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed. The remaining $100 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed on October 15, 2003.

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Summary Pro Forma Financial Data

As discussed under the caption Summary Our Company Recent Developments, on May 14, 2003 NRG filed for bankruptcy protection. This bankruptcy filing will change our accounting for NRG from consolidated reporting to the equity method. The following pro forma financial information reflects adjustments to report NRG on the equity method for the year ended December 31, 2002 and for the nine months ended September 30, 2002. See Unaudited Consolidated Pro Forma Financial Information included in this prospectus for additional information on the pro forma adjustments made, and a reconciliation of historical financial data to pro forma amounts.

	Nine months ended September 30, 2002(1)	Year ended December 31, 2002(1)
	(Millions of dollars)	(Millions of dollars)
Consolidated Statement of Operations Data:		
Operating revenue	$ 5,309	$ 7,243
Operating income	905	1,156
Equity in losses of NRG	(3,123)	(3,464)
Interest charges and financing costs	289	424
Income (loss) from continuing operations	(2,013)	(2,218)

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.1 billion and $3.5 billion for the nine months ended September 30, 2002 and the year ended December 31, 2002, respectively), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

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RISK FACTORS

You should carefully consider the risks described below as well as other information contained in this prospectus before exchanging your original senior notes. The risks described in this section are those that we consider to be the most significant to your decision whether to invest in our exchange senior notes. If any of the events described below occurs, our business, financial condition or results of operations could be materially harmed. In addition, we may not be able to make payments on the exchange senior notes, and this could result in your losing all or part of your investment.

Risks Related to Our Ownership of NRG

Our subsidiary, NRG, is in default under its debt obligations and, along with many of its subsidiaries, has filed a voluntary petition for protection under the bankruptcy laws. The creditors of NRG and its subsidiaries could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of NRG or its subsidiaries and claims under piercing the corporate veil, alter ego, control person or related theories. These claims, if successful, would have a material adverse effect on our financial condition and liquidity, and on our ability to make payments on the exchange senior notes.

Since mid-2002, NRG has experienced severe financial difficulties, resulting primarily from lower prices for power and declining credit ratings. These financial difficulties have caused NRG to, among other things, fail to make payments of interest and/or principal aggregating over $400 million on outstanding indebtedness of over $4 billion and incur asset impairment charges and other costs in excess of $3 billion for the year ended December 31, 2002. These asset impairment charges include write-offs for anticipated losses on sales of several NRG projects as well as anticipated losses related to projects for which NRG has stopped funding. Given the changing business conditions for NRG and the resolution of its plan of reorganization discussed below, additional significant asset impairments may be recorded by NRG.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the Support Agreement between us and NRG dated May 29, 2002. Under the terms of the tentative settlement, which is described in more detail elsewhere in this prospectus, we would pay up to $752 million to NRG to settle claims of NRG against us, including all claims under the Support Agreement, claims of NRG creditors who release us under the NRG plan of reorganization and any potential claims against us for fraudulent transfer, breach of fiduciary duty, payments made by NRG to us, any veil piercing, alter ego or control person theories, unjust enrichment, fraud, misrepresentations and violations of state and federal securities laws.

Commencing on May 14, 2003, NRG and certain of NRG s affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement (based on the settlement discussed above) among us, NRG and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

The NRG plan of reorganization provides that NRG, certain of its direct and indirect majority-owned subsidiaries and each creditor of NRG and its subsidiaries that are Chapter 11 debtors would be deemed to have released us, as of the effective date of the plan of reorganization, from claims against us related to NRG or the NRG bankruptcy, whether or not such creditor has participated in or voted in favor of the plan of reorganization or provided us with a release. However, it is not certain that the bankruptcy court will approve the deemed release by those NRG subsidiaries and NRG creditors that do not voluntarily release us. Moreover, NRG s plan of reorganization, which also incorporates the terms of the overall settlement, might not be confirmed by the bankruptcy court in the form originally filed with the bankruptcy court. Because many of the conditions to the overall settlement, and ultimately confirmation of the entire plan of reorganization, are not within our control, the settlement may not be effectuated in a timely manner, or at all. If the settlement is not effectuated, our potential exposure to NRG and its creditors could exceed $752 million.

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If the overall settlement is not effectuated in the NRG bankruptcy proceeding, NRG or its creditors could seek to substantively consolidate us with NRG or could assert other claims against us under piercing the corporate veil, alter ego, control person or other related theories. Even if the settlement is effectuated, those creditors of NRG who did not release us could seek to substantively consolidate us with NRG or could assert other claims against us under piercing the corporate veil, alter ego, control person or other related theories.

The equitable doctrine of substantive consolidation would permit a bankruptcy court to disregard the separateness of related entities, such as NRG and us, and to consolidate and pool the entities assets and liabilities and treat them as though held and incurred by one entity where the interrelationship among the entities warrants such consolidation. Substantive consolidation is an equitable remedy in bankruptcy that results in the pooling of assets and liabilities of a debtor with one or more of its debtor affiliates or, in very rare circumstances, non-debtor affiliates, solely for the purposes of the bankruptcy case, including treatment under a reorganization plan. The practice of substantive consolidation is not expressly authorized under the U.S. Bankruptcy Code and there are no definitive rules as to when a court will order substantive consolidation. Courts agree, however, that substantive consolidation should be invoked sparingly. A court s decision whether to order substantive consolidation turns primarily on the facts of the case.

Circumstances that courts have generally considered in determining whether to substantively consolidate the assets and liabilities of a debtor and one or more of its affiliated entities in cases under the U.S. Bankruptcy Code include: (a) whether such entities operate independently of one another; (b) whether corporate or other applicable organizational formalities are observed in the operation of such entities; (c) whether the assets of such entities are kept separate and whether records are kept that permit the segregation of the assets and liabilities of such entities; (d) whether such entities hold themselves out to the public as separate entities; (e) whether such entities have maintained separate financial statements; (f) whether such entities have made intercompany guarantees on loans; (g) whether such entities share common officers, directors or employees; (h) whether the creditors have relied on the financial condition of an entity separately from the financial condition of the entity proposed to be consolidated in extending credit; (i) whether the consolidation of, or the failure to consolidate, the assets and liabilities of such entities will result in unfairness to creditors; and (j) whether consolidation of such entities will adversely impact the chances of a successful reorganization.

If NRG or its creditors were to assert claims of substantive consolidation, or piercing the corporate veil, alter ego, control person or related theories, in an NRG bankruptcy proceeding, the bankruptcy court could resolve the issue in a manner adverse to us, thus making our assets available to satisfy NRG s obligations. One of the creditors of an NRG project that filed involuntary bankruptcy proceedings against that project included claims against NRG and has separately made claims against us relating to that project. Other creditors of NRG projects also have threatened, or may threaten, to make similar or other substantial claims against us based on our control of NRG.

If a bankruptcy court were to allow substantive consolidation of us with NRG, or if another court were to allow other related claims against us, it could have a material adverse effect on us and on our ability to make payments on our obligations, including the exchange senior notes, and could ultimately cause us to seek to restructure under the protection of the bankruptcy laws.

If we incur significant liabilities relating to NRG, we may not have sufficient resources to satisfy those claims, and it could adversely affect our ability to make payments on the exchange senior notes.

As discussed above, the bankruptcy court may substantively consolidate us with NRG and make our assets available to satisfy NRG s obligations. Also as discussed above, the overall settlement among us, NRG and NRG s major creditors may not be effectuated.

Even without substantive consolidation, we have certain other potential exposures to claims relating to NRG. In May 2002, we entered into the Support Agreement pursuant to which we agreed to provide up to $300 million to NRG under certain circumstances. As discussed above, we have entered into a settlement with NRG and various NRG credit constituencies pursuant to which we have agreed to pay up to $752 million to settle claims of NRG against us, including claims under the Support Agreement, and claims of NRG creditors who release us under the NRG plan of reorganization. We may be required to provide NRG with these funds.

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We have also provided various guarantees and bond indemnities supporting certain of NRG s and its subsidiaries obligations, guaranteeing the payment or performance under specified agreements or transactions of NRG. As a result, our exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of our guarantees limit our exposure to a maximum amount stated in the guarantees. As of September 30, 2003, the maximum amount stated in our guarantees of obligations of NRG and its subsidiaries was approximately $80 million and our actual aggregate exposure on guarantees of obligations of NRG and its subsidiaries at September 30, 2003 was approximately $5 million, which amount will vary over time. As of September 30, 2003, we had provided indemnities to sureties in respect of bonds for the benefit of NRG and its subsidiaries in an aggregate amount of approximately $6 million. Our exposure under these guarantees and indemnities is addressed in the settlement agreement and there will be no additional exposure beyond the $752 million provided for in the settlement agreement if the settlement agreement is effectuated.

Even without substantive consolidation, we may also have additional potential exposure to certain liabilities relating to employee benefit plans maintained for the benefit of the employees of NRG:

Eligible current or former NRG employees participate in one of our qualified defined benefit pension plans, with the result that our plan is liable for benefits earned by these employees for their past service and may be liable for additional benefits earned by these employees in the future. As part of the settlement discussed above, we have proposed to maintain the NRG benefit formulas for NRG employees in our pension plan until the effective date of the NRG plan of reorganization. Following the effective date, NRG employees would stop actively participating and their benefits earned through the effective date of NRG s plan of reorganization would generally be frozen and would remain obligations of us and our pension plan.

Some current or former NRG employees participate in non-qualified deferred compensation plans that we or other subsidiaries, including NRG, maintain. To the extent NRG fails to pay benefits accrued by its current or former employees under these plans, such employees may seek payment from us. If we are found liable for such payment, it could be material. As part of the settlement discussed above, we would maintain responsibility for only those portions of the benefits under such plans that are legally allocable to us by virtue of prior service by those employees as Xcel Energy or Northern States Power Company employees, which portions will be determined by NRG and Xcel Energy prior to the effective date of the NRG plan of reorganization.

NRG maintains a long-term incentive plan under which options for 2,698,078 of our shares were outstanding as of June 30, 2003. Such options, which had a weighted average exercise price of $29.80 as of June 30, 2003, would become fully exercisable if a change of control (as defined in the plan) of NRG were to occur during or following bankruptcy proceedings.

NRG participates in a multiemployer pension plan covered by Title IV of the Employee Retirement Income Security Act of 1974, as amended (ERISA), with respect to certain employees covered by collective bargaining agreements. If NRG were to withdraw from this plan in a complete or partial withdrawal while it was a member of our controlled group within the meaning of ERISA (generally, subsidiaries of which we own directly or indirectly at least 80 percent), we would be liable under ERISA for any portion of the resulting withdrawal liability imposed under Title IV of ERISA that NRG is unable to pay. If such withdrawal were to occur now, our withdrawal liability may be material.

In addition, we may incur liability for certain tax obligations of NRG. Under regulations issued by the U.S. Department of the Treasury, each member of a consolidated group during any part of a consolidated federal income tax return year is severally liable for the tax obligation of the entire consolidated group for that year. NRG was a member of our consolidated group before March 2001. While NRG may be eligible for re-inclusion in our consolidated group as of June 2002, as part of the overall settlement with us included in NRG s plan of reorganization, NRG would not be reconsolidated. If the IRS determines that NRG owes additional taxes and NRG does not pay them, the IRS would look to one or more members of the consolidated group, including us, for taxes owed by NRG for tax periods when NRG was a member of the consolidated

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group. Under a tax matters agreement to be entered into as part of the settlement, NRG would be obligated to reimburse us for any NRG taxes paid by us to the IRS.

If the settlement is not effectuated, NRG could seek to require that we reconsolidate it and its subsidiaries as of June 2002. If NRG were successful, for income tax reporting the tax rules may prevent us from claiming a worthless stock deduction with respect to our investment in NRG. We could also be required to make certain payments to NRG under our December 2000 tax allocation agreement, which sets forth the rights and responsibilities of the members of our consolidated tax group. While any payments pursuant to that agreement would be funded by tax savings we would realize from the use of NRG s losses, any resulting inability to claim a worthless stock deduction with respect to a reconsolidated NRG could have a material adverse effect on our business, financial condition or results of operations.

We may not have access to adequate funds in the event that we are substantively consolidated with NRG or we incur other significant liabilities relating to NRG. If these events were to occur, it would adversely affect our ability to make payments on the exchange senior notes and you could risk the loss of your entire investment.

Recent and ongoing lawsuits relating to our ownership of NRG could impair our profitability and liquidity and could divert the attention of our management.

On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of our common stock between January 31, 2001 and July 26, 2002, was filed in the United States District Court in Minnesota. The complaint named us; Wayne H. Brunetti, Chairman and Chief Executive Officer; Edward J. McIntyre, former Vice President and Chief Financial Officer; and James J. Howard, former Chairman, as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Rule 10b-5 thereunder related to allegedly false and misleading disclosures concerning various issues, including round trip energy trades, the existence of cross-default provisions in our and NRG s credit agreements with lenders, NRG s liquidity and credit status, the supposed risks to our credit ratings and the status of our internal controls to monitor trading of our power. Thereafter, 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 NRG senior notes issued by NRG in early 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 our credit agreements with lenders for cross-defaults in the event of a default by NRG and, as to the NRG senior notes, also insufficient disclosures concerning the extent to which NRG s fortunes were tied to those of Xcel Energy, especially in the event of a buy-in of NRG public shares. It adds as additional defendants on the claims related to the NRG senior notes Gary R. Johnson, Vice President and General Counsel, Richard C. Kelly, President and Chief Operating Officer, two former executive officers of NRG (David H. Peterson and Leonard A. Bluhm), one current executive officer of NRG (William T. Pieper) and a former independent director of NRG (Luella G. Goldberg); and, as to the NRG senior notes, it adds claims of similar false and misleading disclosures under Section 11 of the Securities Act of 1933. The defendants filed motions to dismiss all the claims, and the court granted the motions in part and denied them in part on September 30, 2003. In an order dated September 30, 2003, the court granted in part and denied in part the defendants motion to dismiss. The court dismissed the claims brought by a sub-class of plaintiffs represented by Catholic Workman. This group consisted of persons who purchased NRG senior notes and alleged false and misleading statements in the registration statement or prospectus under Section 11 of the Securities Act. The court, however, denied the motion with respect to a putative class of plaintiffs consisting of owners of Xcel Energy securities who alleged fraud in violation of Sections 10(b) and 20(a) of the Exchange Act. The defendants expect to file an answer on or about November 14, 2003, and the case is expected to proceed in the normal course as to the claims relating to common stock.

On August 15, 2002, a shareholder derivative action was filed in the United States District Court for the District of Minnesota, purportedly on our behalf, against our directors and certain present and former officers, citing essentially the same circumstances as the class actions described above and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with the securities class actions. After the filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota (and subsequently consolidated with each other), against essentially the same defendants, focusing on allegedly wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish and maintain adequate accounting controls, abuse of control and gross mismanagement. In each of the derivative cases, the defendants have served motions to dismiss the complaint for failure to make a proper pre-suit demand (or, in the federal court case, to make any pre-suit demand at all) upon our board of directors. On October 10, 2003 oral arguments related to the defendants motion to dismiss were presented to the court. The motion was based upon the defendants claim that the plaintiffs failed to satisfy the procedural prerequisites for commencing a shareholder derivative suit. The motion was taken under advisement by the court. None of the motions have yet been ruled upon.

On September 23, 2002 and October 9, 2002, actions were filed in the United States District Court for the District of Colorado, purportedly on behalf of classes of employee participants in our (and our predecessors) 401(k) and employee stock ownership plans from as early as September 23, 1999. The complaints in the actions, which name as defendants Xcel Energy, our directors, certain former directors, and certain of our present and former officers, allege breach of fiduciary duty in allowing or encouraging the purchase, contribution and/or retention of our common stock in the plans and making misleading statements and omissions in that regard. The cases have been transferred by the Judicial Panel on Multidistrict Litigation to the Minnesota federal court for purposes of coordination with the securities class actions and shareholder derivative action pending there. The defendants have filed motions to dismiss the complaints. The motions have not yet been ruled upon.

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

On October 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court for the Southern District of Mississippi against Xcel Energy; Wayne H. Brunetti, Chairman and Chief Executive Officer; Richard C. Kelly, President and Chief Operating Officer, and NRG and certain NRG subsidiaries. Plaintiffs allege they had a contract with a single purpose NRG subsidiary for the construction of a power generation facility, which was abandoned before completion but after substantial sums had been spent by plaintiffs. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy and aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The complaint seeks compensatory damages of at least $130 million plus demobilization and cancellation costs and punitive damages at least treble the compensatory damages. Defendants filed motions to dismiss which were denied, and certain defendants have moved for reconsideration on certain aspects of the motions. The parties have reached a settlement, which settlement is subject to approval by the bankruptcy court in the NRG bankruptcy; further activity in the litigation has been temporarily suspended pending the approval.

If any one or a combination of these cases or other similar claims result in a substantial monetary judgment against us or are settled on unfavorable terms, our results of operations and liquidity could be materially adversely affected.

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Defaults at additional NRG projects could cause us to recognize significant additional losses and write-downs.

We currently account for NRG using the equity method of accounting, which provides for limitations on our recognition of NRG losses. These limitations provide for loss recognition until our investment is written off to zero, and then to continue if financial commitments exist beyond amounts already invested. Beginning with June 30, 2003 quarterly reporting, we have stopped recognizing equity in the losses of NRG. However, given possible changing business conditions at NRG and the pending resolution of its plan of reorganization, additional write-downs or losses of NRG may be required to be recorded by us. We are unable at this time to determine the possible magnitude of any additional such write-downs or losses attributable to NRG activity, but they could be material. Depending on the amount and timing of such losses and write-downs, it could impact our ability to pay dividends on our common stock, due to restrictions under PUHCA discussed below.

Risks Related to Our Liquidity and Access to the Capital Markets

In 2002, our credit ratings were lowered and could be further lowered in the future. If this were to occur, our access to capital would be negatively affected and the value of the exchange senior notes could decline.

Since mid-2002, our credit ratings and access to the capital markets have been significantly and negatively affected, and may be further affected in the future. As of September 30, 2003, our senior unsecured debt was rated BBB- (CreditWatch positive) by Standard & Poor s and Baa3 (stable outlook) by Moody s. Standard & Poor s short-term rating on our commercial paper is A-2. Our commercial paper is rated not prime by Moody s. Any further downgrade of our debt securities would increase our cost of capital and impair our access to the capital markets. This could adversely affect our financial condition and results of operations.

As of October 31, 2003, we had no commercial paper outstanding and had borrowings of approximately $1 million under our five-year credit facility, which matures in November 2005.

As a result of our loss of access to the commercial paper market, we are more dependent upon accessing the capital markets. Access to the capital markets on favorable terms will be impacted by our credit ratings (and the ratings of our affiliated companies) and prevailing conditions in the capital markets.

Our current ratings or those of our affiliates may not remain in effect for any given period of time and a rating may be lowered or withdrawn entirely by a rating agency. In particular, under the current rating methodology used by Standard & Poor s, our ratings could be changed to reflect a change in credit ratings of any of our affiliates. Further, adverse developments related to the NRG bankruptcy case, particularly as they might affect us, could have an adverse effect on our credit ratings and therefore our liquidity. Any lowering of the rating of the exchange senior notes offered hereby would likely reduce the value of the exchange senior notes.

We provide various guarantees and bond indemnities supporting some of our subsidiaries by guaranteeing the payment or performance by those subsidiaries of specified agreements or transactions. Our exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of our guarantees limit our exposure to a maximum amount that is stated in the guarantees. As of September 30, 2003, we had guarantees outstanding with a maximum stated amount of approximately $329 million, of which $80 million related to NRG, and actual aggregate exposure of approximately $18 million, of which $5 million related to NRG, which amount will vary over time. We have provided indemnities to sureties in respect of bonds for the benefit of our subsidiaries. The total amount of bonds with this indemnity outstanding as of September 30, 2003 was approximately $33 million, of which $6 million related to NRG and its subsidiaries.

If either Standard & Poor s or Moody s were to downgrade our credit rating below investment grade, we may be required to provide credit enhancement in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures. If either Standard & Poor s or Moody s were to downgrade our debt securities below investment grade, it would restrict our ability to issue long-term debt securities. See We are subject to regulatory restrictions on accessing capital below.

Any such downgrading of our ratings would increase our cost of capital, impair our access to the capital markets and adversely affect our liquidity position.

Our reduced access to sources of liquidity may increase our cost of capital and our dependence on bank lenders and external capital markets.

Historically, we have relied on bank lines of credit, the commercial paper market and dividends from our regulated utility subsidiaries to meet our cash requirements, including dividend payments to our shareholders, and the short-term liquidity requirements of our business. Given the events at NRG discussed previously and our current short-term ratings, however, we do not have access to the commercial paper market.

Our ability to obtain bank financing on favorable terms could limit our ability to contribute equity or make loans to our subsidiaries, including our regulated utilities, and may cause us and our subsidiaries to seek alternative sources of funds to meet our cash needs.

Furthermore, until the issues related to NRG are resolved, our access to the capital markets may be constrained. Access to the capital markets and our cost of capital will be affected by our credit ratings (and the ratings of our affiliated companies) and prevailing conditions in the capital markets. If we are unable to access the capital markets on favorable terms, our ability to fund our operations and required capital expenditures and other investments may be adversely affected.

Our utility subsidiaries also rely on accessing the capital markets to support their capital expenditure programs and other capital requirements to maintain and build their utility infrastructure and comply with future requirements such as installing emission-control equipment. The ability of our utility subsidiaries to access the capital markets also has been negatively impacted by events at NRG.

We must rely on cash from our subsidiaries to make debt payments.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness, including the exchange senior notes, depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to the exchange senior notes or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary s ability to pay dividends to us depends on any statutory and/or contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets.

As discussed above, our utility subsidiaries are regulated by various state utility commissions which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends to us, it could adversely affect our ability to make payments on the exchange senior notes or otherwise meet our financial obligations.

We are subject to regulatory restrictions on accessing capital.

We are a public utility holding company registered with the SEC under PUHCA. PUHCA contains limitations on the ability of registered holding companies and certain of their subsidiaries to issue securities. Such registered holding companies and subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC.

Because the exemptions available to us are limited, we sought and received financing authority from the SEC under PUHCA for various financing arrangements. Our original financing authority permitted us, subject to satisfaction of certain conditions, to issue through September 30, 2003 up to $2 billion of common stock and

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long-term debt and $1.5 billion of short-term debt at the holding company level. We have issued $2 billion of long-term debt and common stock. Other than the $130 million under our 5-year facility and any current maturities of long-tern debt, we have no short-term debt outstanding at the holding company level. On September 30, 2003, the SEC approved our request for an extension of our financing authority through June 30, 2005 and to increase our authority to issue common stock and long-term debt from $2 billion to $2.5 billion.

One of the conditions of our financing order is that our ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. During 2002 and 2003, we were required to record significant asset impairment losses from sales or divestitures of NRG assets and businesses, from NRG s canceling or deferring the funding of certain projects under construction and from NRG s deciding not to contribute additional funds to certain projects already operating. As a result, our common equity ratio fell below 30 percent. As of September 30, 2003 and taking into account the effects of the deconsolidation of NRG following its bankruptcy filing, our common equity ratio was approximately 40 percent.

If our common equity ratio falls below the 30 percent level, and we are unable to obtain additional relief from the SEC, we may not be able to issue securities (except that we could issue common stock even if our equity ratio is below 30%), which could have a material adverse effect on our ability to make payments on the exchange senior notes and otherwise meet our capital and other needs.

Another condition of our financing order is that (a) if the security to be issued is rated, it is rated investment grade by at least one nationally recognized rating agency and (b) all our outstanding securities (except our preferred stock) that are rated must be rated investment grade by at least one nationally recognized rating agency. As of September 30, 2003, our senior unsecured debt was rated BBB- (CreditWatch positive) by Standard & Poor s and Baa3 (stable outlook) by Moody s, which is investment grade.

PUHCA requires that retained earnings be at least equal to the proposed dividend payment or that we receive a waiver of that requirement from the SEC. As a result of additional write-downs at NRG, our retained earnings were a deficit of approximately $245 million on June 30, 2003. On September 12, 2003, we requested that the SEC release jurisdiction over the payment of common and preferred dividends out of capital and unearned surplus for the third quarter of 2003. No such authorization has yet been received. On September 25, 2003, we announced that our normal third quarter dividend would be delayed.

On September 30, 2003, our retained earnings were approximately $43 million. On October 22, 2003, we declared third quarter dividends on our preferred stock, based on the third quarter results, which indicated sufficient retained earnings were available to do so. The dividends were paid on November 10, 2003 to preferred stock shareholders of record on October 31, 2003. Assuming that the NRG plan of reorganization is approved by NRG s creditors in December 2003 as expected and earnings for 2003 are as anticipated, we currently expect to have retained earnings sufficiently positive before the end of 2003 to pay the third quarter common stock dividend in December as well as declare the fourth quarter common and preferred dividends (normally payable in January 2004).

For additional information regarding our liquidity and capital resources, and the effect that the reductions in our credit ratings have had on our access to capital, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Risks Associated with Our Business

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

We are subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility commissions in the states where our utility subsidiaries operate regulate many aspects of our utility

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operations including siting and construction of facilities, customer service and the rates that we can charge customers.

As a result of the energy crisis in California and the financial troubles at a number of energy companies, including the financial challenges of NRG, the regulatory environments in which we operate have received an increased amount of public attention. The profitability of our utility operations is dependent on our ability to recover costs related to providing energy and utility services to our customers. Although we believe that the current regulatory environment applicable to our business would permit us to recover the costs of our utility services, it is possible that there could be changes in the regulatory environment that would impair our ability to recover costs historically absorbed by our customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. We may be asked to ensure that our ratepayers are not harmed as a result of the credit and liquidity events at NRG. The state utility commissions also may seek to impose restrictions on the ability of our utility subsidiaries to pay dividends to us. If successful, this could materially and adversely affect our ability to meet our financial obligations, including making payments on the exchange senior notes.

In light of the credit and liquidity events regarding NRG, we face enhanced scrutiny from our state regulators. In August 2002, the Minnesota Public Utilities Commission (MPUC) asked for information related to the impact of NRG s financial circumstances on NSP-Minnesota. Subsequent to that date, several local Minneapolis newspaper articles alleged concerns about the reporting of service quality data and NSP-Minnesota s overall maintenance practices. In an order dated October 22, 2002, the MPUC directed the Minnesota Department of Commerce and the Office of the Attorney General Residential Utilities Division to investigate the accuracy of NSP-Minnesota s reliability records and to allow for further review of its maintenance and other service quality measures. In addition, the order requires NSP-Minnesota to report specified financial information and work with interested parties on various issues to ensure its commitments are fulfilled. The October 22, 2002 order references NSP-Minnesota s commitment (made at the time of our merger with New Century Energies, Inc. in August 2000) to not seek an electric base rate increase until 2006 unless certain exceptions are met. In addition, among other requirements, the order imposes restrictions on NSP-Minnesota s ability to encumber utility property, provide intercompany loans and the method by which it can calculate its cost of capital in present and future filings before the MPUC. On March 10, 2003, the Department of Commerce and the Office of the Attorney General submitted a progress report to the MPUC drafted by the agencies auditor. The report documented alleged instances of record keeping inconsistencies and misstatements and concludes it would be nearly impossible to establish the magnitude of misstatements in the record keeping system. NSP-Minnesota has publicly acknowledged that its record keeping system has deficiencies. In submitting the progress report, the state agencies noted, however, that the total outage duration stated would need to increase by nearly 33 million minutes to violate state-imposed standards. On August 4, 2003, the state agencies auditor submitted its final report to the state agencies. NSP-Minnesota believes that the findings in this report are generally consistent with the findings in the auditor s March 10, 2003 report that NSP-Minnesota s record keeping contains inconsistencies and misstatements and that it would be nearly impossible to establish the magnitude of misstatements in the record keeping system. The report also stated that NSP-Minnesota s records were unreliable and appear to have been manipulated to ensure compliance with state-imposed standards. On September 24, 2003, NSP-Minnesota and the state agencies announced that they had reached a settlement agreement. The agreement was submitted to the MPUC for approval. Among the settlement agreement s key provisions were:

$1 million in refunds to Minnesota customers who have experienced the longest duration of outages, which have been accrued at September 30, 2003.

Additional actions to improve system reliability in an effort to reduce outage frequency and duration. These actions will target the primary outage causes, including tree trimming and cable replacement. At least an additional $15 million, above amounts being currently recovered in rates, is to be spent in Minnesota on these outage prevention improvements by January 1, 2005.

Development of a revised service quality plan containing a standard for service outage documentation, new performance measures, new thresholds for current performance measures and a new structure for consequences that will result from failure to meet these performance measures.

NSP-Minnesota is currently negotiating the details of the revised service quality plan with the state agencies. The new service quality plan, or a report on the progress of the negotiations, is expected to be filed with the MPUC on November 14, 2003.

In 2002, the South Dakota Public Utilities Commission (SDPUC) investigated our service quality. In particular, the investigation focused on NSP-Minnesota operations in the Sioux Falls area. NSP-Minnesota committed to a number of actions to improve reliability, which are being implemented, and to provide an updated 10-year capacity plan to the SDPUC by the end of 2003. NSP-Minnesota is working to complete the commitments made in December 2002 relating to service quality in the Sioux Falls area. NSP-Minnesota also is working with the SDPUC to provide information and to answer inquiries regarding service quality. No docket has been opened. If a docket is opened and NSP-Minnesota is found to have violated its service quality obligations, such proceeding could also have a material adverse effect on our financial condition and results of operations.

The Public Service Commission of the State of Wisconsin and the Public Utilities Commission of the State of Colorado (CPUC) have also asked for information related to the impact of NRG s financial circumstances on NSP-Wisconsin and PSCo, respectively. Neither commission has begun a formal investigation, although the CPUC has opened a docket to consider whether PSCo s cost of debt has been adversely affected by the financial difficulties at NRG and, if so, whether any adjustments to PSCo s cost of capital should be made in connection with its 2002 annual electric department earnings test.

The events relating to NRG could also negatively impact the positions taken by the state regulatory commissions in pending and future rate proceedings, which could result in reduced recovery of our costs.

As discussed above, our system also is subject to the jurisdiction of the SEC under PUHCA, which imposes a number of restrictions on the operations of registered holding company systems. These restrictions include, subject to certain exceptions, a requirement that the SEC approve securities issuances, payments of dividends out of capital or unearned surplus, sales and acquisitions of utility assets or of securities of utility companies and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company like us to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce, hydro facility licensing and certain other activities of our utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of our other activities.

We are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including making payments on the exchange senior notes.

We are subject to commodity price risk, credit risk and other risks associated with energy markets.

We are exposed to market and credit risks in our generation, retail distribution and energy trading operations. To minimize the risk of market price and volume fluctuations, we enter into physical and financial derivative instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas, distillate fuel oil, electricity and coal, and emission allowances. However, physical and financial derivative instrument contracts do not completely eliminate risks, including commodity price changes, market supply shortages, credit risk and interest rate changes. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts or increased interest expense.

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

We mark our energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. Quoted market prices are utilized in determining the value of electric energy, natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of eighteen months, and certain short-term positions for which market prices are not available, we utilize models based on forward price curves. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions.

We may be subject to enhanced scrutiny and potential liabilities as a result of our trading operations.

On May 8, 2002, in response to disclosure by Enron Corporation of certain trading strategies used in 2000 and 2001 that may have violated market rules, the FERC ordered all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including us, to respond to data requests, including requests about the use of certain trading strategies. On May 22, 2002, we reported to the FERC that we had not engaged directly in the trading strategies identified in the May 8th inquiry. However, we reported that at times during 2000 and 2001, our regulated operations did sell energy to another energy company that may then have resold the electricity for delivery into California as part of an overstated electricity load in schedules submitted to the California Independent System Operator. During that period, our regulated operations made sales to the other electricity provider of approximately 8,000 megawatt-hours in the California intra-day market, which resulted in revenues to us of approximately $1.5 million. We cannot determine from our records what part of such sales was associated with over-schedules due to the volume of records and the relatively small amount of sales.

To supplement the May 8, 2002 request, on May 21, 2002, the FERC ordered all sellers of wholesale electricity and/or ancillary services in the United States portion of the Western Systems Coordinating Council during 2000 and 2001 to report whether they had engaged in activities referred to as wash, round trip or sell/buyback trading. On May 31, 2002, we reported to the FERC that we had not engaged in so-called round trip electricity trading as identified in the May 21, 2002 inquiry.

On May 13, 2002, independently and not in direct response to any regulatory inquiry, we reported that PSCo had engaged in transactions in 1999 and 2000 with the trading arm of Reliant Resources, Inc. (Reliant) in which PSCo bought power from Reliant and simultaneously sold the same quantity back to Reliant. For doing this, PSCo normally received a small profit. PSCo made a total pretax profit of approximately $110,000 on these transactions. These transactions included one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. In this transaction, PSCo agreed to buy from Reliant 15,000 megawatts per hour, during the off-peak hours of the months of November and December 1999. Collectively, these sales with Reliant consisted of approximately 10 million megawatt hours in 1999 and 1.8 million megawatt hours in 2000 and represented approximately 55 percent of our trading volumes for 1999 and approximately 15 percent of our trading volumes for 2000. The purpose of the non-profit transaction was in expectation of entering into additional future for-profit transactions, such as the ones described above. PSCo engaged in these transactions with Reliant for the proper commercial objective of making a profit. PSCo did not enter into these transactions to inflate volumes or revenues and, at the time the transactions occurred, the transactions were reported net in PSCo s financial statements.

We have also received a subpoena from the SEC for documents concerning round trip trades, as identified in the subpoena, in electricity and natural gas with Reliant for the period from January 1, 1999 to the present. The SEC subpoena is issued pursuant to a formal order of private investigation that does not name us as a subject of the investigation. Based upon accounts in the public press, we believe that similar subpoenas in the same investigation have been served on other industry participants. We are cooperating with the regulators and taking steps to assure satisfactory compliance with the subpoenas.

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If it were to be determined that we acted improperly in connection with these trading activities, we could be subject to a range of potential sanctions, including civil penalties and loss of market-based trading authority.

In addition, a number of actions have been filed in state and federal courts relating to power sales in California and other Western markets from May 2000 through June 2001. Although we and PSCo have not been named in the California litigation, it is possible that we could be brought into the pending litigation, or named in future proceedings. There are also actions pending at FERC regarding these and similar issues. We cannot assure you that we will not have to pay refunds or other damages as a result of these proceedings. Any such refunds or damages could have an adverse effect on our financial condition and results of operations.

Pursuant to a formal order of investigation, on June 17, 2002 the Commodity Futures Trading Commission (CFTC) issued broad subpoenas to us on behalf of our affiliates, including PSCo and NRG, calling for production, among other things, of all documents related to natural gas and electricity trading. Since that time, we have produced documents and other materials in response to numerous more specific requests under the June 17, 2002 subpoenas. Certain of these requests and our responses have concerned so-called round-trip trades. By a subpoena dated January 29, 2003 and related letter requests, the CFTC has requested that we produce all documents related to all data submittals and documents provided to energy industry publications. Also beginning on January 29, 2003, the CFTC has sought testimony from twenty current and former employees and executives, and may seek additional testimony from other employees and executives, concerning the reporting of energy transactions to industry publications. We have produced documents and other materials in response to the January 29, 2003 subpoena, including documents identifying instances where e prime reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions.

As a result of our own ongoing investigation of this matter, representatives of Xcel Energy met on June 12, 2003 with representatives of the CFTC and the Office of the United States Attorney for the District of Colorado. We have determined that e prime employees reported inaccurate trading information to an industry publication and may have reported inaccurate trading information to other industry publications. e prime ceased reporting to publications in 2002. We continue to cooperate in the government s investigation, but cannot predict its outcome.

A number of energy companies have stated in documents filed with the FERC that employees reported fictitious natural gas transactions to industry publications. Several companies have agreed to pay between $3 million and $28 million, to the CFTC to settle alleged violations related to the reporting of fictitious transactions. The CFTC has also brought a civil complaint against an energy company alleging false reporting and attempted market manipulation. In the complaint the CFTC requests damages as well as an order directing the energy company to disgorge benefits received from the alleged illegal acts. These and other energy companies are also subject to a recent order by the FERC placing requirements on natural gas marketers related to reporting, as well as a FERC policy statement regarding reporting of price indices. In addition, two individual traders from the companies that have been fined have been charged in criminal indictments with reporting fictitious transactions.

We continue to investigate this matter, and we and e prime have suspended and/or terminated several employees in connection with the reporting of inaccurate natural gas transactions to industry publications. Nevertheless, we believe that none of e prime s reporting to industry publications had any effect on the financial accounting treatment of any transaction recorded in our books and records. However, we are unable to determine if any reporting of inaccurate trade information to industry publications affected price indices. To date, the investigation indicates that there are no similar issues with respect to electricity trading reporting.

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We received a Notice of Violation from the United States Environmental Protection Agency (EPA) alleging violations of the New Source Review requirements of the Clean Air Act at two of our stations in Colorado and we continue to respond to information requests related to several of our plants in Minnesota. The ultimate financial impact to us is uncertain at this time.

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

On July 1, 2002, we received a Notice of Violation (NOV) from the EPA alleging violations of the NSR requirements at PSCo s 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 were non-routine major modifications and should have required a permit under the NSR process. We believe we acted in full compliance with the Clean Air Act and NSR process. We believe 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. We also believe that the projects would be expressly authorized under the EPA s NSR policy announced by the EPA administrator on June 22, 2002 and proposed in the Federal Register on December 31, 2002. We disagree with the assertions contained in the NOV and intend to vigorously defend our position. As required by the Clean Air Act, the EPA met with us in a conference 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 us is not determinable at this time.

The EPA also issued requests for information pursuant to the Clean Air Act to our subsidiary NSP-Minnesota. In 2001, NSP-Minnesota responded to the EPA s initial information requests related to its plants in Minnesota. On May 22, 2002, the EPA issued a follow-up information request to NSP-Minnesota seeking additional information regarding NSR compliance at its plants in Minnesota. NSP-Minnesota has completed its response to the follow-up information request. NSP-Minnesota believes that it acted in full compliance with the Clean Air Act and the NSR requirements. However, if the EPA disagrees and NSP-Minnesota is unsuccessful in resolving any issues, it may be required to install additional emission control equipment at the facilities at significant cost and pay civil penalties, which could have a material adverse effect on our financial condition and results of operations.

On December 10, 2001, the Minnesota Pollution Control Agency (MPCA) 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. This NOV is separate from and not related to the requests for information discussed above. The MPCA based its notice of violation in part on an EPA determination that the replacement constituted reconstruction of an affected facility under the Clean Air Act s New Source Review requirements. On June 27, 2003, the EPA rejected NSP-Minnesota s request for reconsideration of that determination. The New Source Performance Standard for coal handling systems is unlikely to require the installation of any emission controls not currently in place on the plant. It may impose additional monitoring requirements that would not have material impact on NSP-Minnesota or its operations. In addition, the MPCA or EPA may impose civil penalties for violations of up to $27,500 per day per violation. NSP-Minnesota is working with the MPCA to resolve the notice of violation.

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Our subsidiary, PSCo, has received a notice from the Internal Revenue Service (IRS) proposing to disallow certain interest expense deductions that PSCo claimed in 1993 through 1997. Should the IRS ultimately prevail on this issue, our liquidity position and financial results could be materially adversely affected.

One of PSCo s wholly owned subsidiaries, PSR Investments, Inc. (PSRI), owns and manages, among other things, life insurance policies on some of PSCo s employees known as corporate-owned life insurance (COLI) policies. At various times, PSCo made borrowings against the cash values of these COLI policies and deducted the interest expense on these borrowings. The IRS issued a Notice of Proposed Adjustment to PSCo proposing to disallow interest expense deductions PSCo had taken in tax years 1993 through 1997 related to COLI policy loans. In late 2001, PSCo received a technical advice memorandum from the IRS National Office that communicated a position adverse to PSRI. Consequently, we expect the IRS to continue disallowing the interest deductions and seeking to impose an interest charge on the resulting underpayment of taxes for the tax years 1993 through 1997.

We intend to challenge the IRS determination, which could require several years to reach final resolution. Because it is our position that the IRS determination is not supported by the tax law, PSRI has not recorded any provision for income tax or interest expense related to this matter and continued to take deductions for interest expense related to policy loans on income tax returns for subsequent years. However, defense of our position may require significant cash outlays on a temporary basis if refund litigation is pursued in United States District Court.

The total disallowance of interest expense deductions for the period of 1993 through 1997 is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through December 31, 2002 would reduce earnings by an estimated $214 million (after tax). Because we are continuing to claim deductions for interest expense related to these COLI policy loans, the tax and interest ultimately owed by us, should the IRS ultimately prevail, will continue to increase over time.

Should the IRS ultimately prevail on the COLI policy loan issue, our liquidity position, financial condition and results of operations could be materially adversely affected.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota s two nuclear stations, Prairie Island and Monticello, subject it to the risks of nuclear generation, which include:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities, the storage, handling and disposal of radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the Nuclear Regulatory Commission has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the Nuclear Regulatory Commission could necessitate substantial capital expenditures at NSP-Minnesota s nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident, if an incident did occur, it could have a material adverse effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased

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regulation of the industry as a whole, which could then increase NSP-Minnesota s compliance costs and impact the results of operations of its facilities.

Our subsidiary, SPS, is currently the subject of an investigation by the New Mexico Public Regulation Commission regarding estimated billing practices and may face remedial or punitive action.

Beginning in April 2003, SPS estimated electricity usage for approximately 9,500 customer accounts in two New Mexico cities. Estimated bills were sent to these customers for between two and five months. On September 25, 2003, the New Mexico Public Regulation Commission (the New Mexico Commission) entered an order opening an investigation into SPS practices regarding estimated billing. The commission ordered SPS to show cause why it is not in violation of the commission rule that limits the use of estimated meter readings.

As part of the September 25, 2003 order, the New Mexico Commission also implemented temporary billing measures for customers whose bills were estimated. The temporary billing measures: (i) require SPS to apply the lowest fuel and purchased power cost adjustment factor that was applicable during the period when bills were being estimated, (ii) allow customers 6 months to pay bills in full without additional charges or disconnection, (iii) prohibit disconnection of service until November 1, 2003 for any customer that received an estimated bill, (iv) require SPS to work with the New Mexico Commission s staff on a written explanation of the fuel calculation used under the order, and (v) order SPS to report the amount of fuel and purchased power costs foregone as a result of the interim relief, which amount SPS will not be allowed to recoup from customers. The proceeding has been referred to a hearing examiner. If the investigation into SPS billing practices results in an adverse finding, SPS may be subject to additional remedial actions and civil penalties, which could have a material adverse affect on our financial position and results of operations.

Recession, acts of war or terrorism could negatively impact our business.

The consequences of a prolonged recession and adverse market conditions may include the continued uncertainty of energy prices and the capital and commodity markets. We cannot predict the impact of any continued economic slowdown or fluctuating energy prices. However, such impact could have a material adverse effect on our financial condition and results of operations.

The conflict in Iraq and any other military strikes or sustained military campaign may affect our operations in unpredictable ways and may cause changes in the insurance markets, force us to increase security measures and cause disruptions of fuel supplies and markets, particularly with respect to gas and energy. The possibility that infrastructure facilities, such as electric generation, transmission and distribution facilities, would be direct targets of, or indirect casualties of, an act of war may affect our operations. War and the possibility of further war may have an adverse impact on the economy in general. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets as a result of war may also affect our ability to raise capital.

Further, like other operators of major industrial facilities, our generation plants, fuel storage facilities and transmission and distribution facilities may be targets of terrorist activities that could result in disruption of our ability to produce or distribute some portion of our energy products. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair and insure our assets, which could have a material adverse impact on our financial condition and results of operation.

Increased competition resulting from restructuring efforts could have a significant financial impact on us and our utility subsidiaries and consequently decrease our revenue.

Retail competition and the unbundling of regulated energy and gas service could have a significant financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. The restructuring may have a significant impact on our financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of

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operations or cash flows. We believe that the prices our utility subsidiaries charge for electricity and gas and the quality and reliability of their service currently place them in a position to compete effectively in the energy market.

For additional information regarding the regulatory environment in which we operate and certain other matters regarding our business discussed above, see Notes 1, 15, 18, 19 and 20 to our audited consolidated financial statements and Notes 7 and 8 to our interim consolidated financial statements.

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

Our electric and gas utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. We expect that unusually mild winters and summers would have an adverse effect on our financial condition and results of operations.

Risks Related to the Exchange Senior Notes

The exchange senior notes are effectively subordinated to all existing and future indebtedness and liabilities of our subsidiaries and would have a claim that is junior with respect to the assets securing any secured debt issued by us.

As a stockholder, rather than a creditor of our subsidiaries, our right and the rights of our creditors to participate in the assets of any of our subsidiaries upon any liquidation or reorganization of that subsidiary will rank behind the claims of that subsidiary s creditors, including trade creditors (except to the extent we have a claim as a creditor of such subsidiary). As a result, the exchange senior notes are effectively subordinated to all existing and future indebtedness and other liabilities, including trade payables, of our subsidiaries.

As of September 30, 2003, our subsidiaries had outstanding indebtedness and other liabilities of approximately $12.1 billion. This amount does not include indebtedness and other liabilities of NRG, which was deconsolidated on our financial statements following its bankruptcy filing. Some of these liabilities are secured by the assets of these subsidiaries. We and our subsidiaries may incur additional debt. The indenture governing the exchange senior notes does not contain any restriction on us or our subsidiaries incurring additional debt, including secured debt which would have a prior claim on the assets securing the debt. We would need to obtain certain federal and state regulatory approvals in order to issue secured debt at the holding company level.

Any lowering of the credit ratings of our senior debt would likely reduce the value of the exchange senior notes.

As described above under the caption Risk Factors Risks Related to Our Liquidity and Access to the Capital Markets, our credit ratings were lowered in 2002 and could be further lowered in the future. Any lowering of the credit rating of our senior debt would likely reduce the value of the exchange senior notes offered hereby.

The exchange senior notes have no prior public market and a public market may not develop or be sustained after the offering.

Although the exchange senior notes generally may be resold or otherwise transferred by holders who are not our affiliates without compliance with the registration requirements under the Securities Act, they will constitute a new issue of securities without an established trading market. We have been advised by the initial purchasers that they currently intend to make a market in the exchange senior notes. However, such a market may not develop or, if it does develop, it may not continue. In addition, any such market-making activity may be limited during the exchange offer and during the pendency of any shelf registration that might be filed. If an active public market does not develop, the market price and liquidity of the exchange senior notes may be adversely affected. Furthermore, we do not intend to apply for listing of the exchange senior notes on any securities exchange or automated quotation system.

Even if a market for the exchange senior notes does develop, you may not be able to resell the exchange senior notes for an extended period of time, if at all. In addition, future trading prices for the exchange senior notes will depend on many factors, including, among other things, prevailing interest rates, our financial condition and the market for similar securities. As a result, you may not be able to liquidate your investment quickly or to liquidate it at an attractive price.

Broker-dealers or holders of our senior notes may become subject to the registration and prospectus delivery requirements of the Securities Act.

Any broker-dealer that:

- exchanges its original senior notes in the exchange offer for the purpose of participating in a distribution of the exchange senior notes; or

- exchanges original senior notes that were received by it for its own account in the exchange offer,

may be deemed to have received restricted securities and may be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction by that broker-dealer. Any profit on the resale of the exchange senior notes and any commission or concessions received by a broker-dealer may be deemed to be underwriting compensation under the Securities Act.

In addition to broker-dealers, any holder of senior notes that exchanges its original senior notes in the exchange offer for the purpose of participating in a distribution of the exchange senior notes may be deemed to have received restricted securities and may be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction by that holder of senior notes.

Risks Related to a Failure to Exchange Original Senior Notes for Exchange Senior Notes

You may have difficulty selling the original senior notes which you do not exchange.

If you do not exchange your original senior notes for the exchange senior notes offered in this exchange offer, you will continue to be subject to the restrictions on the transfer of your original senior notes. Those transfer restrictions are described in the indenture and in the legend contained on the original senior notes, and arose because we issued the original senior notes under exemptions from, and in transactions not subject to, the registration requirements of the Securities Act. In general, you may offer or sell your original senior notes only if they are registered under the Securities Act and applicable state securities laws, or if they are offered and sold under an exemption from those requirements. If you do not exchange your original senior notes in the exchange offer, you will no longer be entitled to have those original senior notes registered under the Securities Act.

In addition, if a large number of original senior notes are exchanged for exchange senior notes issued in the exchange offer, the principal amount of original senior notes that will be outstanding will decrease. This will reduce the liquidity of the market for the original senior notes, making it more difficult for you to sell your original senior notes.

You must tender the original senior notes in accordance with proper procedures in order to ensure the exchange will occur.

The exchange of the original senior notes for the exchange senior notes can only occur if the proper procedures, as detailed in this prospectus, are followed. The exchange senior notes will be issued in exchange for the original senior notes only after timely receipt by the exchange agent of the original senior notes or a book-entry confirmation, a properly completed and executed letter of transmittal (or an agent s message in

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lieu thereof) and all other required documentation. If you want to tender your original senior notes in exchange for exchange senior notes, you should allow sufficient time to ensure timely delivery. The exchange agent is not and we are not under any duty to give you notification of defects or irregularities with respect to your tender of original senior notes for exchange. Original senior notes that are not tendered will continue to be subject to the existing transfer restrictions. In addition, if you are an affiliate of ours or you tender the original senior notes in the exchange offer in order to participate in a distribution of the exchange senior notes, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction. Additional information is set forth below under the captions The Exchange Offer and Plan of Distribution.

If a market develops for the exchange senior notes, the exchange senior notes might trade at prices higher or lower than the initial offering price of the original senior notes.

If a market develops for the exchange senior notes, they might trade at prices higher or lower than the initial offering price of the original senior notes. The trading price would depend on many factors, such as prevailing interest rates, the market for similar securities, general economic conditions and our financial condition, performance and prospects.

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USE OF PROCEEDS

We will not receive any cash proceeds from the issuance of the exchange senior notes. The exchange offer is intended to satisfy our obligations under the registration rights agreement that we entered into in connection with the private offering of the original senior notes. In consideration for issuing the exchange senior notes in exchange for the original senior notes as described in this prospectus, we will receive, retire and cancel the original senior notes that are properly offered for exchange. As a result, the issuance of the exchange senior notes will not result in any increase or decrease in our indebtedness. We have agreed to bear the expenses of the exchange offer to the extent indicated in the registration rights agreement. No underwriter is being used in connection with the exchange offer.

The net proceeds from the issuance and sale of the original senior notes, after deducting discounts, commissions and offering expenses, were approximately $193 million. We added the net proceeds from the sale of the original senior notes to our general funds and applied them to repay a portion of outstanding indebtedness under our five-year credit facility.

THE EXCHANGE OFFER

Purpose of the Exchange Offer

We issued and sold the original senior notes on June 24, 2003 in a private placement. In connection with that issuance and sale, we entered into a registration rights agreement with the initial purchasers of the original senior notes. In the registration rights agreement, we agreed to:

- file with the SEC the registration statement of which this prospectus is a part within 120 calendar days of the issue date of the original senior notes (or if such day is not a business day, the next succeeding business day) relating to an offer to exchange the original senior notes for the exchange senior notes;

- cause the registration statement of which this prospectus is a part to be declared effective under the Securities Act within 180 calendar days of the issue date of the original senior notes (or if such day is not a business day, the next succeeding business day); and

- to keep the exchange offer open for at least 20 business days but not more than 30 business days after the date notice of the exchange offer is mailed to holders of original senior notes and use our best efforts to consummate the exchange offer within 210 calendar days of the issue date of the original senior notes (or if such day is not a business day, the next succeeding business day).

The exchange offer being made by this prospectus is intended to satisfy our obligations under the registration rights agreement. If we fail to exchange all validly tendered original senior notes in accordance with the exchange offer on or prior to January 20, 2004, we will be required to pay additional interest to holders of original senior notes until we have complied with this obligation.

Once the exchange offer is complete, we will have no further obligation to register any of the original senior notes not tendered to us in the exchange offer, except to the limited extent that certain qualified institutional buyers, if any, are otherwise entitled to have their original senior notes registered under a shelf registration as described under the caption Exchange Offer and Registration Rights. For a description of the restrictions on transfer of the original senior notes, see Risk Factors Risks Related to the Exchange Senior Notes.

Effect of the Exchange Offer

Based on interpretations by the SEC staff set forth in Exxon Capital Holdings Corporation (available April 13, 1989), Morgan Stanley & Co. Incorporated (available June 5, 1991), Shearman & Sterling (available July 7, 1993) and other no-action letters issued to third parties, we believe that you may offer for resale, resell and otherwise transfer the exchange senior notes issued to you in the exchange offer without compliance with the registration and prospectus delivery requirements of the Securities Act if:

- you are acquiring the exchange senior notes in the ordinary course of your business and do not hold any original senior notes to be exchanged in the exchange offer that were acquired other than in the ordinary course of business;
- you are not a broker-dealer tendering original senior notes acquired directly from us;
- you are not participating, do not intend to participate and have no arrangements or understandings with any person to participate in the exchange offer for the purpose of distributing the exchange senior notes; and
- you are not our affiliate within the meaning of Rule 405 under the Securities Act.

If you are not able to meet these requirements, you are a restricted holder. As a restricted holder, you will not be able to participate in the exchange offer, you may not rely on the interpretations of the SEC staff set forth in the no-action letters referred to above and you may only sell your original senior notes in compliance with the registration and prospectus delivery requirements of the Securities Act or under an exemption from the registration requirements of the Securities Act or in a transaction not subject to the Securities Act.

We do not intend to seek our own no-action letter, and there can be no assurance that the staff of the SEC would make a similar determination with respect to the exchange senior notes as it has in such no-action letters to third parties.

In addition, if the tendering holder is a broker-dealer that will receive exchange senior notes for its own account in exchange for original senior notes that were acquired as a result of market-making or other trading activities, it may be deemed to be an underwriter within the meaning of the Securities Act. Any such holder will be required to acknowledge in the letter of transmittal that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of these exchange senior notes. This prospectus may be used by those broker-dealers to resell exchange senior notes they receive pursuant to the exchange offer. We have agreed that we will allow this prospectus to be used by any broker-dealer in any resale of exchange senior notes until July 16, 2004 (210 days from the completion of this exchange offer).

Except as described above, this prospectus may not be used for an offer to resell, resale or other transfer of exchange senior notes.

To the extent original senior notes are tendered and accepted in the exchange offer, the principal amount of original senior notes that will be outstanding will decrease with a resulting decrease in the liquidity in the market for the original senior notes. Original senior notes that are still outstanding following the completion of the exchange offer will continue to be subject to transfer restrictions.

Terms of the Exchange Offer

Upon the terms and subject to the conditions of the exchange offer described in this prospectus and in the accompanying letter of transmittal, we will accept for exchange all original senior notes validly tendered and not withdrawn before 5:00 p.m., New York City time, on the expiration date. We will issue $1,000 principal amount of exchange senior notes in exchange for each $1,000 principal amount of original senior notes accepted in the exchange offer. You may tender some or all of your original senior notes pursuant to the exchange offer. However, original senior notes may be tendered only in increments of $1,000.

The exchange offer is not conditioned upon any minimum aggregate principal amount of original senior notes being tendered for exchange. As of the date of this prospectus, an aggregate of $195 million principal amount of original senior notes was outstanding. This prospectus is being sent to all registered holders of original senior notes. There will be no fixed record date for determining registered holders of original senior notes entitled to participate in the exchange offer.

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We intend to conduct the exchange offer in accordance with the applicable requirements of the Securities Act and the Exchange Act and the rules and regulations of the SEC. Holders of original senior notes do not have any appraisal or dissenters rights under law or under our Indenture dated December 1, 2000 (the Indenture), as amended and supplemented, in connection with the exchange offer. Original senior notes that are not tendered for exchange in the exchange offer will remain outstanding and continue to accrue interest and will be entitled to the rights and benefits their holders have under the Indenture, as amended and supplemented.

We will be deemed to have accepted for exchange validly tendered original senior notes when we have given oral or written notice of the acceptance to the exchange agent. The exchange agent will act as agent for the tendering holders of original senior notes for the purposes of receiving the exchange senior notes from us and delivering the exchange senior notes to the tendering holders.

If we do not accept for exchange any tendered original senior notes because of an invalid tender, the occurrence of certain other events described in this prospectus or otherwise, such unaccepted original senior notes will be returned, without expense, to the holder tendering them or the appropriate book-entry will be made, in each case, as promptly as practicable after the expiration date.

We are not making, nor is our board of directors making, any recommendation to you as to whether to tender or refrain from tendering all or any portion of your original senior notes in the exchange offer. No one has been authorized to make any such recommendation. You must make your own decision whether to tender your original senior notes in the exchange offer and, if you decide to do so, you must also make your own decision as to the aggregate amount of original senior notes to tender after reading this prospectus and the letter of transmittal and consulting with your advisers, if any, based on your own financial position and requirements.

Expiration Date; Extensions; Amendments

The term expiration date means 5:00 p.m., New York City time, on December 19, 2003, unless we, in our sole discretion, extend the exchange offer, in which case the term expiration date shall mean the latest date and time to which the exchange offer is extended.

If we determine to extend the exchange offer, we will notify the exchange agent of any extension by oral or written notice.

We reserve the right, in our sole discretion:

- to delay accepting for exchange any original senior notes; or
- to extend or terminate the exchange offer and to refuse to accept original senior notes not previously accepted if any of the conditions set forth below under Conditions to the Exchange Offer have not been satisfied by the expiration date.

Without limiting the manner in which we may choose to make public announcements of any delay in acceptance, extension, termination or amendment of the exchange offer, we will have no obligation to publish, advertise or otherwise communicate any public announcement, other than by making a timely release to a financial news service.

During any extension of the exchange offer, all original senior notes previously tendered will remain subject to the exchange offer. We will return any original senior notes that we do not accept for exchange for any reason without expense to the tendering holder as promptly as practicable after the expiration or earlier termination of the exchange offer.

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Procedures for Tendering

In order to exchange your original senior notes, you must complete one of the following procedures by 5:00 p.m., New York City time, on the expiration date:

if your original senior notes are in book-entry form, the book-entry procedures for tendering your original senior notes must be completed as described below under Book-Entry Transfer ;

if you hold physical original senior notes that are registered in your name (*i.e.*, not in book-entry form), you must transmit a properly completed and duly executed letter of transmittal, certificates for the original senior notes you wish to exchange and all other documents required by the letter of transmittal, to Wells Fargo Bank Minnesota, National Association, the exchange agent, at its address listed below under Exchange Agent ; or

if you cannot tender your original senior notes by either of the above methods by the expiration date, you must comply with the guaranteed delivery procedures described below under Guaranteed Delivery Procedures.

A tender of original senior notes by a holder that is not withdrawn prior to the expiration date will constitute an agreement between that holder and us in accordance with the terms and subject to the conditions set forth in this prospectus and in the letter of transmittal.

The method of delivery of original senior notes through DTC and the method of delivery of the letter of transmittal and all other required documents to the exchange agent is at the holder s election and risk. Holders should allow sufficient time to effect the DTC procedures necessary to validly tender their original senior notes to the exchange agent before the expiration date. Holders should not send letters of transmittal or other required documents to us.

We will determine, in our sole discretion, all questions as to the validity, form, eligibility (including time of receipt), acceptance of tendered original senior notes and withdrawal of tendered original senior notes, and our determination will be final and binding. We reserve the absolute right to reject any and all original senior notes not properly tendered or any original senior notes the acceptance of which would, in our opinion or in the opinion of our counsel, be unlawful. We also reserve the absolute right to waive any defects or irregularities or conditions of the exchange offer as to any particular original senior notes either before or after the expiration date. Our interpretation of the terms and conditions of the exchange offer as to any particular original senior notes either before or after the expiration date, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of original senior notes for exchange must be cured within such time as we shall determine. Although we intend to notify holders of any defects or irregularities with respect to tenders of original senior notes for exchange, neither we nor the exchange agent nor any other person shall be under any duty to give such notification, nor shall any of them incur any liability for failure to give such notification. Tenders of original senior notes will not be deemed to have been made until all defects or irregularities have been cured or waived. Any original senior notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned by the exchange agent to the tendering holders or, in the case of original senior notes delivered by book-entry transfer within DTC, will be credited to the account maintained within DTC by the participant in DTC that delivered such original senior notes, unless otherwise provided in the letter of transmittal, as soon as practicable following the expiration date.

In addition, we reserve the right in our sole discretion (a) to purchase or make offers for any original senior notes that remain outstanding after the expiration date, (b) as set forth below under Conditions to the Exchange Offer, to terminate the exchange offer and (c) to the extent permitted by applicable law, purchase original senior notes in the open market, in privately negotiated transactions or otherwise. The terms of any such purchases or offers could differ from the terms of the exchange offer.

By signing, or otherwise becoming bound by, the letter of transmittal, each tendering holder of original senior notes (other than certain specified holders) will represent to us that:

it is acquiring the exchange senior notes and it acquired the original senior notes being exchanged in the ordinary course of its business;

it is not a broker-dealer tendering original senior notes acquired directly from us;

it is not participating, does not intend to participate and has no arrangements or understandings with any person to participate in the distribution (within the meaning of the Securities Act) of the exchange senior notes; and

it is not our affiliate, within the meaning of Rule 405 under the Securities Act, or, if it is our affiliate, it will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable.

If the tendering holder is a broker-dealer that will receive exchange senior notes for its own account in exchange for original senior notes that were acquired as a result of market-making activities or other trading activities, it may be deemed to be an underwriter within the meaning of the Securities Act. Any such holder will be required to acknowledge in the letter of transmittal that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of these exchange senior notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, the broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act.

Book-Entry Transfer

If your original senior notes are in book-entry form and are registered in the name of a broker, dealer, commercial bank, trust company or other nominee, you must contact the registered holder of your original senior notes and instruct it to promptly tender your original senior notes for exchange on your behalf.

The exchange agent will establish an account with respect to the original senior notes at DTC promptly after the date of this prospectus. Your book-entry senior notes must be transferred into the exchange agent s account at DTC in compliance with DTC s transfer procedures in order for your original senior notes to be validly tendered for exchange. Any financial institution that is a participant in DTC s systems may cause DTC to transfer original senior notes to the exchange agent s account. The DTC participant, on your behalf, must transmit its acceptance of the exchange offer to DTC. DTC will verify this acceptance, execute a book-entry transfer of the tendered original senior notes into the exchange agent s account and then send to the exchange agent confirmation of this book-entry transfer. The confirmation of this book-entry transfer will include an agent s message confirming that DTC has received an express acknowledgement from the DTC participant that the DTC participant has received and agrees to be bound by the letter of transmittal and that we may enforce the letter of transmittal against this participant. Original senior notes will be deemed to be validly tendered for exchange only if the exchange agent receives the book-entry confirmation from DTC, including the agent s message, prior to the expiration date.

All references in this prospectus to deposit or delivery of original senior notes shall be deemed to also refer to DTC s book-entry delivery method.

Guaranteed Delivery Procedures

Holders who wish to tender their original senior notes and (1) whose original senior notes are not immediately available or (2) who cannot deliver the letter of transmittal or any other required documents to the exchange agent prior to the expiration date or (3) who cannot complete the procedures for book-entry transfer on a timely basis may effect a tender if:

the tender is made through an eligible institution;

before the expiration date, the exchange agent receives from the eligible institution a properly completed and duly executed notice of guaranteed delivery, by facsimile transmission, mail or hand

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delivery, listing the principal amount of original senior notes tendered, stating that the tender is being made thereby and guaranteeing that, within three New York Stock Exchange, Inc. trading days after the expiration date, a duly executed letter of transmittal, together with a confirmation of book-entry transfer of such original senior notes into the exchange agent s account at DTC and any other documents required by the letter of transmittal and the instructions thereto, will be deposited by such eligible institution with the exchange agent; and

within three New York Stock Exchange trading days after the expiration date, the exchange agent receives a confirmation of book-entry transfer of all original senior notes tendered by the eligible institution into the exchange agent s account at DTC in the case of book-entry original senior notes, or a properly completed and executed letter of transmittal and the physical original senior notes, in the case of original senior notes in certificated form, and all other documents required by the letter of transmittal.

Upon request to the exchange agent, a notice of guaranteed delivery will be sent to holders who wish to tender their original senior notes according to the guaranteed delivery procedures described above.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, tenders of original senior notes may be withdrawn at any time prior to 5:00 p.m., New York City time, on the expiration date.

For a withdrawal to be effective, the exchange agent must receive a written or facsimile transmission notice of withdrawal at the address set forth below under Exchange Agent. Any notice of withdrawal must:

specify the name of the person who tendered the original senior notes to be withdrawn;

identify the original senior notes to be withdrawn, including the principal amount of such original senior notes;

state that the holder is withdrawing its election to exchange the original senior notes to be withdrawn;

be signed by the holder in the same manner as the original signature on the letter of transmittal by which the original senior notes were tendered and include any required signature guarantees; and

specify the name and number of the account at DTC to be credited with the withdrawn original senior notes and otherwise comply with the procedures of DTC.

We will determine, in our sole discretion, all questions as to the validity, form and eligibility (including time of receipt) of any notice of withdrawal, and our determination shall be final and binding on all parties. Any original senior notes so withdrawn will be deemed not to have been validly tendered for exchange for purposes of the exchange offer, and no exchange senior notes will be issued with respect thereto unless the original senior notes so withdrawn are validly re-tendered. Properly withdrawn original senior notes may be re-tendered by following one of the procedures described above under Procedures for Tendering at any time prior to the expiration date.

Any original senior notes that are tendered for exchange through the facilities of DTC but that are not exchanged for any reason will be credited to an account maintained with DTC for the original senior notes as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer.

Conditions to the Exchange Offer

Despite any other term of the exchange offer, we will not be required to accept for exchange, or to issue exchange senior notes in exchange for, any original senior notes, and we may terminate the exchange offer as provided in this prospectus prior to the expiration date, if:

we are not permitted to effect the exchange offer according to the registration rights agreement because of any change in law, regulation or any applicable interpretation of the SEC staff; or

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- a pending or threatened action or proceeding would impair our ability to proceed with the exchange offer.

These conditions are for our sole benefit and may be asserted by us regardless of the circumstances giving rise to any of these conditions or may be waived by us, in whole or in part, at any time and from time to time in our reasonable discretion. Our failure at any time to exercise any of the foregoing rights shall not be deemed a waiver of the right and each right shall be deemed an ongoing right which may be asserted at any time and from time to time.

If we determine in our reasonable judgment that any of the conditions are not satisfied, we may:

- refuse to accept and return to the tendering holder any original senior notes or credit any tendered original senior notes to the account maintained within DTC by the participant in DTC which delivered the original senior notes;

- extend the exchange offer and retain all original senior notes tendered before the expiration date, subject to the rights of holders to withdraw the tenders of original senior notes (see Withdrawal of Tenders above); or

- waive the unsatisfied conditions with respect to the exchange offer prior to the expiration date and accept all properly tendered original senior notes that have not been withdrawn or otherwise amend the terms of the exchange offer in any respect as provided under Expiration Date; Extensions; Amendments.

In addition, we will not accept for exchange any original senior notes tendered, and we will not issue exchange senior notes in exchange for any of the original senior notes, if at that time any stop order is threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture under the Trust Indenture Act of 1939.

Exchange Agent

Wells Fargo Bank Minnesota, National Association has been appointed as the exchange agent for the exchange offer. All signed letters of transmittal and other documents required for a valid tender of your original senior notes should be directed to the exchange agent at the address set forth below. Questions and requests for assistance, requests for additional copies of this prospectus or of the letter of transmittal and requests for notices of guaranteed delivery should be directed to the exchange agent addressed as follows:

By Registered, Certified or by Hand or Overnight Delivery:	*By Facsimile:*
	Attention: Michael T. Lechner
Wells Fargo Bank Minnesota, National Association MAC# N9303-121 Corporate Trust Services, 11th Floor 6th & Marquette Avenue Minneapolis, Minnesota 55479	612-667-2160 *Confirmation of Facsimile:* 612-316-4305

For information regarding the exchange offer, call: 800-344-5128

Delivery to other than the above address or facsimile number will not constitute a valid delivery.

Fees and Expenses

We will bear the expenses of soliciting tenders for the exchange offer. These expenses include fees and expenses of the exchange agent and the trustee, the registration fee, accounting and legal fees, printing costs and related fees and expenses. We will principally solicit tenders for the exchange offer by mail or overnight courier, although our officers and regular employees may additionally solicit in person or by telephone or facsimile.

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We have not retained any dealer-manager in connection with the exchange offer and will not pay any brokers, dealers or others soliciting acceptance of the exchange offer. We, however, will pay the exchange agent reasonable and customary fees for its services and its reasonable out-of-pocket expenses. We may also pay brokerage houses and other custodians, nominees and fiduciaries their reasonable out-of-pocket expenses for sending copies of this prospectus, letters of transmittal and related documents to holders of the original senior notes and in tendering original senior notes for their customers.

Transfer Taxes

Holders who tender their original senior notes for exchange will not be obligated to pay any transfer taxes in connection with the exchange offer.

Accounting Treatment

We will recognize no gain or loss, for accounting purposes, as a result of the exchange offer. The expenses of the exchange offer and the unamortized expenses relating to the issuance of the original senior notes will be amortized over the term of the exchange senior notes.

Consequences of Failure to Exchange

Holders of original senior notes who do not exchange their original senior notes for exchange senior notes pursuant to the exchange offer will not be able to offer, sell or otherwise transfer the original senior notes except in compliance with the registration requirements of the Securities Act and other applicable securities laws, pursuant to an exemption from the securities laws or in a transaction not subject to the securities laws. Original senior notes not exchanged pursuant to the exchange offer will otherwise remain outstanding in accordance with their respective terms and will continue to bear a legend reflecting these restrictions on transfer. Holders of original senior notes do not have any appraisal or dissenters rights under the Minnesota Business Corporation Act in connection with the exchange offer.

Upon completion of the exchange offer, holders of original senior notes will not be entitled to any rights to have the resale of original senior notes registered under the Securities Act except to the limited extent that certain qualified institutional buyers, if any, are otherwise entitled under the registration rights agreement to have their original senior notes registered under a shelf registration. Except for this limited circumstance, we do not intend to register under the Securities Act the resale of any original senior notes that remain outstanding after completion of the exchange offer.

RATIO OF EARNINGS TO FIXED CHARGES

	Nine months ended September 30,		Year ended December 31,				
	2003	2002	2002	2001	2000	1999	1998
Ratio of Earnings to Fixed Charges	2.2	(1)	(2)	2.0	1.9	2.4	3.0

(1) Earnings as defined in the ratio for the nine months ended September 30, 2002 were reduced by NRG asset impairment charges of $2.5 billion. The fixed charges exceeded earnings, as defined in this ratio, by $2.1 billion for the nine months ended September 30, 2002.

(2) Earnings as defined in the ratio for the twelve months ended December 31, 2002 were reduced by NRG asset impairment charges of $2.5 billion. The fixed charges exceeded earnings, as defined for this ratio, by $2.3 billion in 2002.

For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of earnings from continuing operations plus fixed charges, federal and state income taxes, deferred income taxes and investment tax credits and less undistributed equity in earnings of unconsolidated investees, and (2) fixed charges consist of interest on long-term debt, other interest charges, distributions on redeemable preferred securities of subsidiary trusts and amortization of debt discount, premium and expense.

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2003, which excludes NRG due to its deconsolidation in the second quarter of 2003. We will not receive any proceeds from the exchange of the exchange notes for outstanding original senior notes. You should read the information in this table together with the detailed information and financial statements appearing in this prospectus and with Selected Consolidated Financial Data included elsewhere in this prospectus.

	As of September 30, 2003	
	(Thousands of dollars)	(% of Capitalization)
Short-term debt, including current maturities	$ 389,971	3.33%
Long-term debt	6,411,736	54.68
Minority interest	5,433	0.05
Mandatorily redeemable preferred securities of subsidiary trust(1)	100,000	0.85
Preferred stockholder s equity	104,260	0.89
Common stockholder s equity	4,714,330	40.20
Total capitalization (including short-term debt and minority interest)	$ 11,725,730	100.0%

(1) On July 31, 2003, $200 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed. The remaining $100 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed on October 15, 2003.

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SELECTED CONSOLIDATED FINANCIAL DATA

The following selected consolidated financial data as of December 31, 2002 and 2001, and for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 have been derived from our audited consolidated financial statements and the related notes. The consolidated financial data as of September 30, 2003 and 2002 have been derived from our unaudited interim consolidated financial statements. The information set forth below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited and unaudited consolidated financial statements and related notes and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Nine months ended September 30,		Year ended December 31,				
	2003	2002	2002(1)	2001	2000	1999	1998
	(Millions of dollars, except per share data)						
Consolidated Income Statement Data:							
Operating revenue(2)	$5,975	$ 7,068	$ 9,524	$11,333	$9,223	$6,883	$6,606
Operating expense(2)	5,136	8,597	10,957	9,475	7,744	5,679	5,412
Operating income (loss)	839	(1,529)	(1,433)	1,858	1,479	1,204	1,194
Interest income and other nonoperating income-net of other expenses	31(3)(4)	44(3)	44	46	16	3	49
Interest charges and financing costs	343	585	918	766	653	453	383
Income taxes (benefits)	40	(609)	(628)	331	299	180	240
Equity in losses of NRG	(364)						
Minority interest in NRG losses		14					
Minority interest (income) expense			(17)	68	30	3	
(Loss) income from continuing operations before extraordinary items	124	(1,447)	(1,661)	738	514	571	620
(Loss) income from discontinued operations, net of tax	21	(566)	(557)	47	32		4
Extraordinary items, net of tax				10	(19)		
Net (loss) income	145	(2,013)	(2,218)	795	527	571	624
Dividends on preferred stock	3	3	4	4	4	5	5
(Loss) earnings available for common shareholders	$ 142	$(2,016)	$ (2,222)	$ 791	$ 523	$ 566	$ 619
Earnings per share diluted:							
(Loss) income from continuing operations before extraordinary items	$ 0.31	$ (3.85)	$ (4.36)	$ 2.13	$ 1.51	$ 1.70	$ 1.91
Discontinued operations	0.05	(1.50)	(1.46)	0.14	0.09		
Extraordinary items				0.03	(0.06)		
Total	$ 0.36	$ (5.35)	$ (5.82)	$ 2.30	$ 1.54	$ 1.70	$ 1.91

(1) Results for 2002 include two significant items which are described further in the notes to our consolidated financial statements: (a) impairment charges and disposal losses (excluding discontinued operations) related to NRG s long-lived assets and equity investments, which increased operating expenses and reduced operating income for the year ended December 31, 2002 by $2.7 billion; reduced net income and earnings available for common shareholders for the year ended December 31, 2002 by $2.6 billion; and reduced earnings per share for the year ended December 31, 2002 by $6.80; and (b) income tax benefits related to our investment in NRG which increased income from continuing operations and net income for the year ended December 31, 2002 by $706 million, and increased earnings per share from continuing operations and total earnings per share for the year ended December 31, 2002 by $1.85.

(2) Operating revenues and expenses for 1998 through 2001 include reclassifications to conform to the 2002 presentation. These reclassifications related to reporting of electric and natural gas trading revenues and costs on a net basis, and to presenting the results of discontinued operations separately. These reclassifications had no effect on net income or earnings per share.

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(3) Interest income and other nonoperating income-net of other expenses consists of interest income, equity in unconsolidated affiliates (other than NRG) and other nonoperating income, less minority interest expense (other than NRG) and other nonoperating expense. See Note 12 to the interim consolidated financial statements.

(4) Does not include NRG activity as NRG is accounted for under the equity method of accounting beginning in the second quarter of 2003.

	September 30, 2003(1)	December 31, 2002	2001	2000	1999	1998
	(Millions of dollars)					
Consolidated Balance Sheet Data:						
Current assets	$ 3,118	$ 3,737	$ 3,330	$ 3,128	$ 2,061	$ 1,557
Property, plant and equipment, at cost	12,770	18,816	19,781	15,273	12,799	10,560
Other assets	2,376	4,705	5,642	3,368	3,210	2,938
Total assets	$18,264	$27,258	$28,754	$21,769	$18,070	$15,055
Current portion of long-term debt	241	7,756(2)	393	604	431	507
Short-term debt	149	1,542	2,225	1,475	1,433	764
Other current liabilities	2,404	3,051	2,851	2,593	1,619	1,286
Total current liabilities	2,794	12,349	5,469	4,672	3,483	2,557
Deferred credits and other liabilities	4,135	3,060	4,321	3,075	2,855	2,732
Minority interest	5	35	615	277	15	14
Long-term debt	6,412	6,550	11,556	7,584	5,828	4,057
Mandatorily redeemable preferred securities of subsidiary trust(3)	100	494	494	494	494	494
Preferred stockholder s equity	104	105	105	105	105	105
Common stockholder s equity	4,714	4,665	6,195	5,562	5,290	5,096
Total liabilities and equity	$18,264	$27,258	$28,754	$21,769	$18,070	$15,055

(1) Balances have decreased due to the deconsolidation of NRG in the second quarter of 2003.

(2) Based on the defaults under certain NRG debt agreements, and NRG s lenders having the ability to call such debt within twelve months of December 31, 2002, the majority of NRG s long-term debt has been reclassified to current as of that date.

(3) On July 31, 2003, $200 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed. The remaining $100 million of mandatorily redeemable preferred securities of subsidiary trusts were redeemed on October 15, 2003.

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SELECTED PRO FORMA CONSOLIDATED FINANCIAL DATA

As discussed elsewhere in this prospectus, NRG voluntarily filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 14, 2003. As part of this action, the tentative settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG s creditors (the Settlement) was filed with the bankruptcy court for its consideration as a resolution of NRG s financial difficulties. If the court approves the terms of the Settlement, upon emergence from bankruptcy Xcel Energy will divest its ownership interests in NRG. However, pending the outcome of the bankruptcy proceeding, Xcel Energy will remain 100 percent owner of NRG but will not have sufficient control to continue consolidating NRG. During the period between NRG s filing for bankruptcy and its actual divestiture by Xcel Energy, Xcel Energy will report NRG as an equity investment under generally accepted accounting principles. Beginning with June 30, 2003 quarterly reporting (the first period that includes the bankruptcy filing date), Xcel Energy has reclassified the 2003 net operating results of NRG as equity in losses of NRG in the statement of operations retroactive to January 1, 2003, as required under the accounting rules governing a mid-year change from consolidating a subsidiary to accounting for the investment using the equity method. However, the presentation of NRG in the historical financial statements as a consolidated subsidiary in 2002 and prior periods will not change from the prior presentation. Because such accounting requirements do not allow equity accounting until the period that includes the bankruptcy filing, Xcel Energy is providing investors with pro forma information for historical periods presenting NRG under the equity method of accounting.

The following selected pro forma consolidated financial data for Xcel Energy gives effect to the change of accounting for NRG from consolidated financial reporting to the equity method of accounting. Under the equity method, NRG is not consolidated in Xcel Energy s financial statements but instead is reported as a single item (Equity in Losses of NRG) on the Statements of Operations.

The following selected pro forma income statement data is treated as if Xcel Energy had never consolidated NRG for financial reporting purposes. This unaudited pro forma summarized financial information should be read in conjunction with the historical financial statements and related notes of Xcel Energy included herein. The unaudited pro forma income statement information for the nine months ended September 30, 2002, and the year ended December 31, 2002, assumes that NRG had been deconsolidated on January 1, 2002, the beginning of the earliest period presented.

These summarized pro forma amounts do not include any of the future financial impacts that may occur from NRG s filing for bankruptcy, or from implementing the Settlement. Also, the unaudited summarized pro forma financial information does not necessarily indicate what Xcel Energy s operating results would have been if NRG had filed for bankruptcy (or had been divested) in the periods presented, and does not necessarily indicate future operating results of Xcel Energy (with or without NRG).

The following selected pro forma consolidated financial data for the year ended December 31, 2002 have been derived from our consolidated financial statements and the related notes. The following selected pro forma consolidated financial data for the nine months ended September 30, 2002 have been derived from our interim consolidated financial statements and the related notes. The information set forth below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited consolidated financial statements and related notes and our interim consolidated financial information and related notes. See Unaudited Consolidated Pro Forma Financial Information included in this prospectus for additional information on the pro forma adjustments made, and a reconciliation of

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historical financial data to pro forma amounts. The pro forma financial information may not be indicative of our future performance.

	Nine months ended September 30, 2002(1)	Year ended December 31, 2002(1)
	(Millions of dollars, except per share data)	
Consolidated Statement of Operations Data:		
Operating revenue	$ 5,309	$ 7,243
Operating expense	4,404	6,087
Operating income	$ 905	$ 1,156
Interest income and other nonoperating income net of other expenses	25	40
Minority interest in NRG losses	14	
Equity in losses of NRG	(3,123)	(3,464)
Interest charges and financing costs	289	424
Income taxes (benefits)	(456)	(462)
Minority interest (income) expense		(12)
Income (loss) from continuing operations	(2,103)	(2,218)
Earnings (loss) per share from continuing operations basic and diluted	$ (5.35)	$ (5.82)

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.1 billion and $3.5 billion for the nine months ended September 30, 2002 and the year ended December 31, 2002, respectively), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with Summary Summary Consolidated Financial Data, Summary Summary Pro Form Financial Data, Selected Consolidated Financial Data, Selected Pro Forma Consolidated Financial Data and our financial statements and related notes appearing elsewhere in this prospectus. This discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. See Special Note Regarding Forward-Looking Statements. The actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors including, but not limited to, those set forth under Special Note Regarding Forward-Looking Statements and Risk Factors in this prospectus.

Overview

On August 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Company (NSP) merged and formed Xcel Energy Inc. (Xcel Energy). Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). As part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of Xcel Energy named Northern States Power Company. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. As a stock-for-stock exchange for shareholders of both companies, the merger was accounted for as a pooling-of-interests and, accordingly, amounts reported for periods prior to the merger have been restated for comparability with post-merger results.

We directly own five utility subsidiaries that serve electric and natural gas customers in 11 states. These five utility subsidiaries are Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); Southwestern Public Service Company (SPS); and Cheyenne Light, Fuel and Power Company (Cheyenne). They serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Our regulated businesses also include WestGas InterState Inc. (WGI), an interstate natural gas pipeline company. Prior to January 2003, our regulated businesses included Viking Gas Transmission Company. On October 20, 2003, we completed the sale of Black Mountain Gas Company (BMG), which serves customers in portions of Arizona.

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. (NRG), an independent power producer. We owned 100 percent of NRG at the beginning of 2000. About 18 percent of NRG was sold to the public in an initial public offering in the second quarter of 2000, leaving us with an 82-percent interest at December 31, 2000. In March 2001, another 8 percent of NRG was sold to the public, leaving us with an interest of about 74 percent at December 31, 2001. On June 3, 2002, we acquired the 26 percent of NRG held by the public so that we again held 100 percent ownership at December 31, 2002. As discussed in more detail below, on May 14, 2003, NRG and some of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. See Notes 4, 5 and 6 to the interim consolidated financial statements filed with this prospectus. We have reached a tentative settlement with NRG and some of NRG s creditors. If the bankruptcy court approves the terms of this settlement, we will divest our ownership interest in NRG when NRG emerges from bankruptcy.

In addition to NRG, our nonregulated subsidiaries include Utility Engineering Corporation (UE) (engineering, construction and design), Seren Innovations, Inc. (Seren) (broadband telecommunications services), e prime, Inc. (e prime) (natural gas marketing and trading), Planergy International Inc. (Planergy) (energy management consulting and demand-side management services), Eloigne Company (Eloigne) (ownership of rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (XEI) (international independent power producer).

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Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on our 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 audited and interim consolidated financial statements and notes included in this prospectus.

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. The forward-looking statements are intended to be identified in this document by the words believe, anticipate, estimate, expect, intend, plan, may, should, objective, outlook, potential and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to:

general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures and our ability and the ability of our subsidiaries to obtain financing on favorable terms;

business conditions in the retail and wholesale energy industry;

competitive factors, including the extent and timing of the entry of additional competition in the markets served by us and our subsidiaries;

unusual weather;

state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates structures and affect the speed and degree to which competition enters the electric and gas markets;

the higher risk associated with our nonregulated businesses compared with our regulated businesses;

the financial condition of NRG and the actions by the bankruptcy court in NRG s bankruptcy proceedings;

costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including without limitation claims brought against us by creditors, shareholders or others relating to our ownership of NRG;

failure to realize expectations regarding the NRG settlement agreement;

the effect on the U.S. economy as a consequence of war and acts of terrorism;

currency translation and transaction adjustments; and

risks associated with the California power market.

Results of Operations

The table below summarizes the earnings per share contributions of our businesses for the nine months ended September 30, 2003 on both a generally accepted accounting principles (GAAP) basis and a pro forma basis. We are presenting pro forma earnings to reflect our operating results excluding businesses that were or are expected to be divested this year, as assumed in the previously disclosed earnings guidance. The pro forma results exclude the gain on the sale of Viking Gas Transmission Co., the impact of tax benefits related to our investment in NRG and the results of NRG. The results of NRG under the equity method of accounting are excluded from our 2003 results, as required by GAAP. See Note 5 to the interim consolidated financial statements. Viking Gas was sold in January 2003, and we expect the outcome of NRG s financial

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restructuring will be the divestiture of NRG in 2003. The pro forma results are provided to reflect our ongoing operations on a comparative basis for 2003 and 2002.

	Nine months ended September 30,	
	2003	2002
GAAP Earnings (Loss) by Segment:		
Regulated electric utility segment earnings	$ 0.90	$ 1.07
Regulated natural gas utility segment earnings continuing operations	0.13	0.13
Other utility results*		0.03
Total utility segment earnings continuing operations	1.03	1.23
Utility earnings discontinued operations (gain from Viking Gas sale)*	0.05	
Total earnings from utility segments	1.08	1.23
NRG earnings (loss) continuing operations	(0.91)	(6.75)
NRG earnings (loss) discontinued operations		(1.50)
Total loss from NRG segment	(0.91)	(8.25)
Other nonregulated results/ holding company costs*	(0.07)	(0.13)
Tax benefit from investment in NRG (at holding company)*	0.26	1.80
Total GAAP earnings (loss) per share diluted	$ 0.36	$(5.35)
Reconciliation of Pro forma Results to GAAP Earnings (Loss):		
Total utility segment earnings continuing operations:	$ 1.03	$ 1.23
Other nonregulated results/ holding company costs	(0.07)	(0.13)
Pro forma continuing operations, excluding NRG	0.96	1.10
Total NRG segment loss	(0.91)	(8.25)
Tax benefit from investment in NRG (at holding company)*	0.26	1.80
Utility earnings discontinued operations (gain on Viking Gas)*	0.05	
Total GAAP earnings (loss) per share diluted	$ 0.36	$(5.35)

* Not a reportable segment. Included in All Other segment results in Note 11 to the interim consolidated financial statements.

Common Stock Dilution Dilution from stock issued in the first and second quarters of 2002 reduced the utility segment earnings contribution by 6 cents per share, and the total loss by 2 cents per share, for the nine months ended September 30, 2003.

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The table below summarizes our earnings per share for each of the three years ended December 31, 2002, 2001 and 2000. Note references relate to the Notes to the audited consolidated financial statements.

	Year ended December 31,		
	2002	2001	2000
Contribution to Earnings per Share			
Continuing Operations Before Extraordinary Items:			
Regulated utility	$ 1.59	$ 1.90	$ 1.20
NRG (including impairments and restructuring charges)	(7.58)	0.44	0.37
Other nonregulated and holding company (including tax benefits related to investment in NRG in 2002)	1.63	(0.21)	(0.06)
Income (loss)from continuing operations	(4.36)	2.13	1.51
Discontinued operations NRG (see Note 3)	(1.46)	0.14	0.09
Extraordinary items Regulated utility (see Note 15)		0.03	(0.06)
Total earnings (loss) per share diluted	$(5.82)	$ 2.30	$ 1.54

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

	Year ended December 31,		
	2002	2001	2000
Contribution to Earnings per Share			
Regulated utility (including extraordinary items):			
Electric utility	$ 1.33	$ 1.66	$ 1.03
Gas utility	0.26	0.24	0.17
Total regulated utility	1.59	1.90	1.20
NRG (including discontinued operations) (see Note 3)	(9.04)	0.58	0.46
Other nonregulated and holding company:			
Tax benefit related to investment in NRG	1.85	0.00	0.00
Other (see Note 21 for components)	(0.22)	(0.18)	(0.12)
Total earnings (loss) per share diluted	$(5.82)	$ 2.30	$ 1.54

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

Significant Factors that Impacted Results for the Nine Months Ended September 30, 2003

Special Charges Holding Company Costs During the first nine months of 2003, we incurred approximately $12 million for charges at the holding company level related to NRG s financial restructuring, including $3 million in the third quarter of 2003.

As discussed further in Note 5 to the interim consolidated financial statements, all of NRG s results for 2003 are reported in a single line item, Equity in Losses of NRG, due to the deconsolidation of NRG as a result of its bankruptcy filing in May 2003. NRG s 2003 results do reflect some effects of asset impairments and restructuring costs, which are discussed in Note 5 to the interim consolidated financial statements, but are not presented as a special charge in 2003.

Significant Factors that Impacted Results for the Nine Months Ended September 30, 2002

Special Charges *NRG Special Charges* In the second quarter of 2002, NRG expensed pretax charges of $36 million, or 6 cents per share, related to its NEO projects and $20 million, or 4 cents per share, for expected severance and related benefits. Additional severance accruals of $6 million, or 1 cent per share, were made in the third quarter of 2002. Through September 30, 2002, severance costs had been recognized for

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all employees who had been terminated as of that date. Another $12 million, or 2 cents per share, of other NRG restructuring costs were recorded in the third quarter of 2002, including financial advisors, legal advisors and consultants. In addition, NRG also recorded a $16 million charge to income in the third quarter of 2002 for a decrease in the value of a remarketing option.

Due to financial difficulties, NRG s continuing operations incurred $2.6 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 in the third quarter of 2002, included write-downs of $2.2 billion for projects in development, $265 million for operating projects and $117 million for equity investments.

Special Charges Regulatory Recovery Adjustment During the first quarter of 2002, SPS wrote off approximately $5 million, or 1 cent per share, of restructuring costs relating to costs incurred to comply with legislation requiring a transition to retail competition in Texas, which was subsequently amended to delay the required transition.

Special Charges Utility Restaffing During the fourth quarter of 2001, we recorded an estimated liability for expected staff consolidation costs for an estimated 500 employees in several of our utility operating and corporate support areas. In the first quarter of 2002, the identification of affected employees was complete and additional pretax special charges of $9 million, or approximately 1 cent per share, were expensed for the final costs of the utility-related staff consolidations. All 564 of accrued staff terminations have occurred.

Special Charges Other During the third quarter of 2002, Xcel Energy International disposed of its remaining interest in Yorkshire Power LLC in the United Kingdom, resulting in a pre-tax loss of $1.1 million and an after-tax loss of $8.3 million, or 2 cents per share.

Significant Factors that Impacted 2002 Results

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

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

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

NRG also expensed approximately $111 million in 2002 for incremental costs related to its financial restructuring and business realignment. These costs, which reduced 2002 earnings by 27 cents per share, include expenses for financial and legal advisors, contract termination costs, employee separation and other incremental costs incurred during the financial restructuring period. These costs also include a charge related to NRG s NEO landfill gas generation operations for the estimated impact of a dispute settlement with

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NRG s partner on the NEO project, Fortistar. Most of these costs were paid in 2002. See Note 2 to the audited consolidated financial statements for discussion of accrued financial restructuring cost activity related to NRG.

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

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

Significant Factors that Impacted 2001 Results

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

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

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

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

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

Significant Factors that Impacted 2000 Results

Special Charges Merger Costs During 2000, we expensed pretax special charges of $241 million, or 52 cents per share, for costs related to the merger between NSP and NCE. Of these special charges, approximately 44 cents per share were associated with the costs of merging regulated utility operations and

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8 cents per share were associated with merger impacts on nonregulated and holding company activities other than NRG. See Note 2 to the audited consolidated financial statements for more information on these merger-related costs reported as Special Charges.

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

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 has changed from 2002 to 2003. For 2002, 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 will be able to collect 100 percent of its retail electric fuel and purchased energy expense through the interim adjustment clause (IAC). In addition to the IAC, Colorado has other adjustment clauses that allow certain costs to be recovered from retail customers.

We have three distinct forms of wholesale sales: short-term wholesale, electric commodity trading and natural gas commodity trading. Short-term wholesale refers to electric sales for resale, which are associated with energy produced from our generation assets or energy and capacity purchased to serve native load. Electric and natural gas commodity trading refers to the sales for resale activity of purchasing and reselling electric and natural gas energy to the wholesale market. Short-term wholesale and electric trading activities are considered part of the electric utility segment, while the natural gas commodity trading is considered part of the All Other segment.

Our commodity trading operations are conducted by NSP-Minnesota (electric), PSCo (electric) and e prime (natural gas). Margins from electric trading activity, conducted at NSP-Minnesota and PSCo, are partially redistributed to other of our operating utilities pursuant to a joint operating agreement (JOA) approved by the FERC. PSCo s short-term wholesale margins and electric trading margins reflect the impact of regulatory sharing, if applicable, of certain margins with Colorado retail customers. Trading results are reported net of related costs (*i.e.*, on a margin basis) in the consolidated statements of operations. Trading revenue and costs associated with NRG s operations are included in the NRG segment results, not reflected in

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the table below. The following table details the revenue and margin for base electric utility, short-term wholesale and electric and natural gas trading activities.

	Base Electric Utility	Short-Term Wholesale	Electric Commodity Trading	Natural Gas Commodity Trading	Inter-Company Eliminations	Consolidated Totals
			(Millions of dollars)			
Nine months ended September 30, 2003						
Electric utility revenue	$ 4,364	$ 144	$	$	$	$ 4,508
Electric fuel and purchased power utility	(1,951)	(99)				(2,050)
Electric and natural gas trading revenue gross			256	507	(26)	737
Electric and natural gas trading costs			(241)	(504)	26	(719)
Gross margin before operating expenses	$ 2,413	$ 45	$ 15	$ 3	$	$ 2,476
Margin as a percentage of revenue	55.3%	31.3%	5.9%	0.6%	%	47.2%
Nine months ended September 30, 2002						
Electric utility revenue	$ 3,985	$ 132	$	$	$	$ 4,117
Electric fuel and purchased power utility	(1,544)	(107)				(1,651)
Electric and natural gas trading revenue gross			1,351	1,511	(57)	2,805
Electric and natural gas trading costs			(1,353)	(1,505)	57	(2,801)
Gross margin before operating expenses	$ 2,441	$ 25	$ (2)	$ 6	$	$ 2,470
Margin as a percentage of revenue	61.3%	18.9%	(0.1)%	0.4%	%	35.7%
Year ended December 31, 2002						
Electric utility revenue	$ 5,232	$ 203	$	$	$	$ 5,435
Electric fuel and purchased power utility	(2,029)	(170)				(2,199)
Electric and natural gas trading revenue gross			1,529	1,898	(71)	3,356
Electric and natural gas trading costs			(1,527)	(1,892)	71	(3,348)
Gross margin before operating expenses	$ 3,203	$ 33	$ 2	$ 6	$	$ 3,244
Margin as a percentage of revenue	61.2%	16.3%	0.1%	0.3%		36.9%

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	Base Electric Utility	Short-Term Wholesale	Electric Commodity Trading	Natural Gas Commodity Trading	Inter-Company Eliminations	Consolidated Totals
			(Millions of dollars)			
Year ended December 31, 2001						
Electric utility revenue	$ 5,607	$ 788	$	$	$	$ 6,395
Electric fuel and purchased power utility	(2,559)	(613)				(3,172)
Electric and natural gas trading revenue gross			1,337	1,938	(88)	3,187
Electric and natural gas trading costs			(1,268)	(1,918)	88	(3,098)
Gross margin before operating expenses	$ 3,048	$ 175	$ 69	$ 20	$	$ 3,312
Margin as a percentage of revenue	54.4%	22.2%	5.2%	1.0%		34.6%
Year ended December 31, 2000						
Electric utility revenue	$ 5,107	$ 567	$	$	$	$ 5,674
Electric fuel and purchased power utility	(2,106)	(475)				(2,581)
Electric and natural gas trading revenue gross			819	1,297	(54)	2,062
Electric and natural gas trading costs			(788)	(1,287)	54	(2,021)
Gross margin before operating expenses	$ 3,001	$ 92	$ 31	$ 10	$	$ 3,134
Margin as a percentage of revenue	58.8%	16.2%	3.8%	0.8%		40.5%

Nine Months Ended September 30, 2003 Comparison to Nine Months Ended September 30, 2002 Base electric utility margins decreased by approximately $28 million for the first nine months of 2003 compared with the first nine months of 2002. The lower base electric margin reflects cooler June temperatures, higher purchased capacity costs in 2003 and the positive impact of incentive cost adjustment mechanisms in 2002, partially offset by weather-normalized sales growth and accrued recovery of Minnesota renewable development fund costs.

Short-term wholesale and electric and natural gas commodity trading sales margins increased approximately $37 million for the first nine months of 2003 compared with the same period in 2002. The increase reflects more favorable market conditions in the northern regions and reduced transmission costs.

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

Short-term wholesale margins consist of asset-based trading activity. Electric and natural gas commodity trading activity margins consist of non-asset-based trading activity. Short-term wholesale and electric and natural gas commodity trading sales margins decreased an aggregate of approximately $223 million in 2002, compared with 2001. The decrease in short-term wholesale and electric commodity trading margin reflects

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lower power prices and less favorable market conditions. The decrease in natural gas commodity trading margin reflects reduced market opportunities.

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

Short-term wholesale revenue increased by approximately $221 million, or 39.0 percent, in 2001. Short-term wholesale margin increased $83 million, or 90.2 percent, in 2001. These increases are due to the expansion of our wholesale marketing operations and favorable market conditions for the first six months of 2001, including strong prices in the western markets, particularly before the establishment of price caps and other market changes.

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

Natural Gas Utility Margins

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

	Nine months ended September 30,		Year ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**
			(Millions of dollars)		
Natural gas utility revenue	$1,123	$ 938	$1,398	$ 2,053	$1,469
Cost of natural gas purchased and transported	(758)	(559)	(852)	(1,518)	(948)
Natural gas utility margin	$ 365	$ 379	$ 546	$ 535	$ 521

Nine Months Ended September 30, 2003 Comparison to Nine Months Ended September 30, 2002 Natural gas revenue increased by approximately $185 million, or 19.7 percent, in the first nine months of 2003 compared with the same period in 2002, primarily due to increases in the wholesale cost of natural gas, which are largely passed on to customers and recovered through various rate adjustment clauses in most of the jurisdictions in which we operate. Natural gas margin decreased by approximately $14 million, primarily due to the impact of warmer-than-normal weather, and the sale of Viking Gas in January 2003, partially offset by weather-normalized firm sales growth.

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

2001 Comparison to 2000 Natural gas utility revenue increased by approximately $584 million, or 39.8 percent, for 2001, primarily due to increases in the cost of natural gas, which are largely passed on to

customers and recovered through various rate adjustment clauses in most of the jurisdictions in which we operate. Natural gas utility margin increased by approximately $14 million, or 2.7 percent, for 2001 due to sales growth and a rate increase in Colorado. These natural gas revenue and margin increases were partially offset by the impact of warmer temperatures in 2001, which decreased natural gas revenue by approximately $38 million and natural gas margin by approximately $16 million.

Nonregulated Operating Margins

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

	Nine months ended September 30,		Year ended December 31,		
	2003(1)	**2002(2)**	**2002**	**2001**	**2000**
			(Millions of dollars)		
Nonregulated and other revenue	$ 326	$ 1,938	$ 2,611	$ 2,580	$1,856
Earnings from equity investments		70	72	217	183
Nonregulated cost of goods sold	(221)	(1,002)	(1,361)	(1,319)	(877)
Nonregulated margin	$ 105	$ 1,006	$ 1,322	$ 1,478	$1,162

(1) Excludes NRG s operations.

(2) Nonregulated operating margin includes the following attributable to NRG s operations (in millions of dollars):

Nonregulated and other revenue	$1,689
Earnings from equity investments	70
Nonregulated cost of goods sold	(839)
Nonregulated margin	920

Nine Months Ended September 30, 2003 Comparison to Nine Months Ended September 30, 2002 Excluding operations at NRG, nonregulated revenues and margins increased in the first nine months of 2003 compared to the same period in 2002 due mainly to increasing customer levels in Seren s communication business, higher contract revenues in Xcel Energy International s Argentina operations, and increased retail service revenues. These margin increases were offset by higher operating and other costs, including costs of goods sold.

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

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

Non-Fuel Operating Expense and Other Items

Nine Months Ended September 30, 2003 Comparison to Nine Months Ended September 30, 2002 Utility operating and maintenance expenses for the nine months ended September 30, 2003 increased

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approximately $61 million, or 5.6 percent, compared with the same period in 2002. The increase is due primarily to higher employee benefit costs related to lower pension credits, higher medical and health care costs, higher incentive costs and restricted stock unit grants, as well as higher outage costs, partly offset by lower information technology costs.

Excluding NRG amounts in 2002, depreciation and amortization increased by approximately $13 million, or 2.3 percent, for the first nine months of 2003, compared with 2002, primarily due to $14 million of Minnesota renewable development fund costs, which are largely recovered through NSP-Minnesota s fuel clause mechanism, and increased software amortization, partially offset by lower depreciation rates at PSCo in 2003.

Excluding NRG amounts in 2002, interest expense increased by approximately $60 million for the first nine months of 2003, compared with 2002. This increase is due to the issuance of long- and intermediate-term debt to reduce dependence on short-term debt at the holding company, NSP-Minnesota and PSCo.

Excluding NRG amounts in 2002 and tax benefits related to the investment in NRG, income taxes changed due to a change in pretax income and to a lesser extent to changes in the effective tax rate. The effective tax rate for non-NRG operations and excluding worthless stock deduction benefits was 27.5 percent in the first nine months of 2003 and 34.4 percent in the same period of 2002. The change in the effective tax rate between years reflects a larger ratio of tax credits to the lower pretax income levels in 2003, adjustments to 2002 and 2003 state tax accruals recorded in 2003 related to updated income apportionment by state (including NRG impacts) and NSP-Minnesota adjustments due to favorable tax audit settlements in 2003. The change is likely to also result in a decrease in the 2003 annual effective tax rate for Xcel Energy, excluding NRG impacts. See Note 6 to the interim consolidated financial statements for a discussion of tax benefits related to the investment in NRG.

2002 Comparison to 2001 Other utility operating and maintenance expense for 2002 decreased by approximately $4 million, or 0.3 percent. The decreased costs reflect lower incentive compensation and other employee benefit costs, as well as lower staffing levels in corporate areas. These decreases were substantially offset by higher plant outage and property insurance costs, in addition to inflationary factors such as market wage increases.

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

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

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

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

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

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

Including NRG amounts, income tax expense decreased by approximately $959 million in 2002, compared with 2001. Nearly all of this decrease relates to NRG s 2002 losses and the change in tax filing status for NRG effective in the third quarter of 2002, as discussed in Note 11 to the audited consolidated financial statements. NRG is now in a tax operating loss carryforward position and is no longer assumed to be

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part of our consolidated tax group. The effective tax rate for continuing operations, excluding minority interest and before extraordinary items, was 27.3 percent for the year ended December 31, 2002, and 28.8 percent for the same period in 2001. The decrease in the effective rate between years reflects a nominal tax rate at NRG, due to their loss carryforward position. Partially offsetting the NRG tax rate decrease is the impact of a one-time adjustment to recognize tax benefits from our investment in NRG, as discussed in Note 11 to the audited consolidated financial statements. The effective tax rate for the regulated utility business and operations other than NRG was significantly lower in 2002, compared with 2001, due to the benefit recorded on the investment in NRG and the changes in the items listed in the rate reconciliation in Note 11.

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

Weather

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

- weather in the first nine months of 2003 increased earnings by an estimated 2 cents per share;
- weather in 2002 increased earnings by an estimated 6 cents per share;
- weather in 2001 had minimal impact on earnings per share; and
- weather in 2000 increased earnings by an estimated 1 cent per share.

NRG Results

Results for the Nine Months Ended September 30, 2003 and the Nine Months Ended September 30, 2002 Equity Method

As discussed in Note 5 to the interim consolidated financial statements, as a result of NRG s bankruptcy filing in May 2003, the presentation of NRG results is not comparable in the accompanying financial statements. NRG s results for 2003 are presented under the equity method, on a single line, Equity in Losses of NRG. Results for 2002 are presented in the Statement of Operations with NRG consolidated as a part of us. However, unaudited consolidated pro forma financial information for 2002 is included with this prospectus, which provides 2002 information for NRG s results on a basis comparable with the 2003 presentation.

NRG s results summarized on an overall basis are as follows:

	Nine months ended September 30, 2003	Nine months ended September 30, 2002
	(in millions)	
Total NRG loss*	$(906)	$(3,123)
Losses (income) not recorded by Xcel Energy under the equity method**	542	
Equity in losses of NRG included in Xcel Energy results	$(364)	$(3,123)

* Includes discontinued operations related to several projects that have been sold or are pending sale by NRG. For 2003 reporting, no distinction is made under the equity method for the underlying NRG projects, whether discontinued or continuing.

** These represent NRG losses incurred in the second quarter of 2003 that were in excess of the amounts recordable by us under the equity method of accounting limitations discussed previously.

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

NRG s results in 2002 include restructuring costs and asset impairments, reported as Special Charges in Operating Expenses, as discussed in Note 2 to the interim consolidated financial statements.

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 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 to 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), we 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, we recorded our equity in NRG results for the second quarter (including these impairments) in excess of our financial commitment to NRG under the settlement agreement. These excess losses of $106 million will be reversed and recognized as a non-cash gain upon NRG s emergence from bankruptcy. During the third quarter of 2003, NRG recorded a $396 million charge in connection with the resolution of an arbitration with FirstEnergy. See Note 5 to the interim consolidated financial statements for further discussion of the 2003 change in accounting for NRG and our limitation for recognizing NRG s losses due to its bankruptcy filing.

As of September 30, 2003, NRG s 2003 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.

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

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NRG Results For the Years Ended December 31, 2002, 2001 and 2000 Consolidated

Results for the years ended December 31, 2002, 2001 and 2000 are presented with NRG consolidated as a part of us. Note references relate to the Notes to the audited consolidated financial statements.

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

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

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

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

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

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Other Nonregulated Subsidiaries and Holding Company Results

The table below summarizes the earnings-per-share contributions of our nonregulated businesses other than results recorded by NRG, and holding company results other than tax benefits from the investment in NRG.

	Nine months ended September 30,		Year ended December 31,		
	2003	2002	2002	2001	2000
Other Nonregulated and Holding Company Results:					
Xcel Energy International	$ 0.02	$ (0.02)	$ (0.05)	$ (0.02)	$ 0.09
Eloigne Company	0.01	0.02	0.02	0.03	0.02
Seren Innovations	(0.03)	(0.04)	(0.07)	(0.08)	(0.07)
Planergy International	(0.01)	(0.01)	0.00	(0.04)	(0.08)
e prime, Inc.			0.00	0.02	(0.02)
Financing costs and preferred dividends	(0.09)	(0.08)	(0.11)	(0.11)	(0.07)
Other nonregulated/ holding company results	0.03	0.00	(0.01)	0.02	0.01
Subtotal nonregulated/ holding co. excluding tax benefit	(0.07)	(0.13)	(0.22)	(0.18)	(0.12)
Tax benefit from investment in NRG (Note 11 to audited and Note 6 to interim consolidated financial statements)	0.26	1.80	1.85		
Total nonregulated/ holding company earnings per share	$ 0.19	$ 1.67	1.63	$ (0.18)	$ (0.12)

Xcel Energy International Xcel Energy International is currently comprised primarily of power generation projects in Argentina, and previously included an investment in Yorkshire Power.

Earnings in the nine months ended September 30, 2003 increased compared to the same period in 2002 due mainly to losses incurred in 2002 related to the sale of the remaining interests in Yorkshire Power in the United Kingdom. Also, earnings for the nine months ended September 30, 2003 include a gain from a debt restructuring for one project, which increased earnings by approximately 1 cent per share.

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

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

Eloigne Company Eloigne invests in affordable housing that qualifies for Internal Revenue Service tax credits. Earnings results for the nine months ended September 30, 2003 declined slightly compared to the nine months ended September 30, 2002 due to the sale of a partnership interest. Eloigne s earnings contribution declined slightly in 2002 as tax credits on mature affordable housing projects began to decline. The actual

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decline in Eloigne s net income in 2002, compared with 2001, was only $716,000, with 2002 earnings representing 2.1 cents per share and 2001 earnings representing 2.5 cents per share.

Seren Innovations Seren operates a combination cable television, telephone and high-speed Internet access system in St. Cloud, Minnesota, and Contra Costa County, California. Operation of its broadband communications network has resulted in losses. Seren projects improvement in its operating results with positive cash flow anticipated in 2005, upon completion of its build-out phase, and a positive earnings contribution anticipated in 2008. At September 30, 2003, our investment in Seren was approximately $266 million.

Planergy International Planergy, a wholly owned subsidiary of us, provides energy management services. Planergy s results for the nine months ended September 30, 2003 reflect severance costs and costs associated with the exit from certain business activities. Planergy s results for 2002 improved, largely due to gains from the sale of a portfolio of energy management contracts, which increased earnings by nearly 2 cents per share.

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

e prime e prime s results for the nine months ended September 30, 2003 reflect unfavorable market conditions. As a result of the market and liquidity concerns, e prime lowered its level of trading to minimize risk to its contractual portfolio. These lower margins were insufficient to recover all of e prime s operating expenses.

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

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

Financing Costs and Preferred Dividends Nonregulated and holding company results include interest expense and preferred dividend costs, which are incurred at the Xcel Energy and intermediate holding company levels, and are not directly assigned to individual subsidiaries. Holding company financing costs have increased due to the issuance of convertible debt in November 2002 and long-term debt in June 2003.

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

Other Certain costs, including costs related to NRG s restructuring, are being incurred at the holding company level. In the third quarter of 2003, Utility Engineering sold water rights, resulting in a pretax gain (reported as nonoperating income) of $15 million. Results for the nine months ended September 30, 2003 also increased due to income tax adjustments related to changing state tax effects resulting from NRG tax deconsolidation and losses, partially offset by lower income from Utility Engineering and NRG restructuring costs, as discussed in Note 2 to the interim consolidated financial statements.

Approximately $5 million of NRG restructuring costs were incurred in 2002, which reduced earnings by approximately 1 cent per share.

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

Tax Benefit from Investment in NRG The table above includes holding company tax impacts related to NRG. In the third quarter of 2003, Xcel Energy recorded $105 million, or 25 cents per share, of tax benefit related to its investment in NRG, as discussed in Note 6 to the interim consolidated financial statements.

Factors Affecting Results of Operations

Our utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions. In addition, our nonregulated businesses have adversely affected our earnings in 2002 and the first nine months of 2003. The historical and future trends of our operating results have been, and are expected to be, affected by the following factors:

Impact of NRG Bankruptcy As discussed elsewhere in this prospectus, on May 14, 2003, NRG and some of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. We have reached a tentative settlement with NRG and some of NRG s creditors. If the bankruptcy court approves the terms of this settlement, we will divest our ownership interest in NRG when NRG emerges from bankruptcy.

As a result of the bankruptcy, we have discontinued the consolidation of NRG retroactive to January 1, 2003, and for the year 2003 and are reporting NRG results under the equity method of accounting. See Note 5 of the interim consolidated financial statements for further discussion of the accounting impacts of deconsolidating NRG in 2003.

Prior to NRG s bankruptcy filing on May 14, 2003, we had recognized NRG losses in excess of our investment in NRG, as discussed in Note 5 to the interim consolidated financial statements. Effective as of the bankruptcy filing date, we ceased the consolidation of NRG and began accounting for our 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. See Note 5 to the interim consolidated financial statements. Our exposure to NRG losses subsequent to its deconsolidation is limited under the equity method to our financial commitments to NRG.

In accordance with the limitations under the equity method, we have stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provide for loss recognition until our investment is written off to zero, with further loss recognition to continue if financial commitments to NRG exist beyond amounts already invested. As of September 30, 2003, we had recognized NRG losses to the point where they exceeded the investment made in NRG by $858 million, $106 million more than the amount of the up to $752 million financial commitment to NRG under the settlement agreement discussed below. The losses recognized in excess of the financial commitment will be reversed and recognized as a non-cash gain upon NRG s emergence from bankruptcy. If the final amount of financial commitments changes as a result of bankruptcy proceedings, the level of equity in NRG losses recorded by us would also change accordingly at that time. We have reflected these excess losses as a negative investment on the accompanying balance sheet in other current liabilities, based on our expectation that NRG s plan of reorganization will take effect, and the settlement payments will be made, within 12 months of the bankruptcy filing.

The estimated financial commitment to NRG, based on the terms of the settlement agreement, includes total settlement payments by us related to NRG of up to $752 million. NRG losses recognized in excess of the $752 million in settlement payments will be reversed and recognized as a non-cash gain upon NRG s emergence from bankruptcy. However, should the settlement agreement not ultimately be approved by NRG s creditors and/or the bankruptcy court, the amount of financial assistance committed to NRG could be different from those amounts, pending the ultimate resolution of NRG s bankruptcy. Prior to reaching the settlement agreement, we and NRG had entered into a support and capital subscription agreement in 2002 pursuant to which we agreed, under certain circumstances, to provide a $300 million contribution to NRG.

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Upon effectiveness of the NRG plan of reorganization, our obligations under the support and capital subscription agreement would be terminated.

In addition to the effects of NRG s losses, our operating results and retained earnings in 2003 could also be affected by future tax effects of any financial commitments to NRG, if such income tax benefits were considered likely to be realized in the foreseeable future. See Note 6 to the interim consolidated financial information for further discussion of tax benefits related to our investment in NRG.

The accompanying interim consolidated financial statements do not necessarily reflect future conditions or matters that may arise as a result of NRG s bankruptcy filing and its ultimate resolution. Pending the outcome of its voluntary bankruptcy petition, NRG remains subject to substantial doubt as to its ability to continue as a going concern. For a further description of the impact on us of the NRG s financial situation in 2002, see Note 4 to the audited consolidated financial statements.

We believe that the ultimate resolutions of NRG s financial difficulties and going concern uncertainty will not affect our ability to continue as a going concern. We are not dependent on cash flows from NRG. We believe that our cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund our non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, we believe we will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

General Economic Conditions The slower United States economy, and the global economy to a lesser extent, may have a significant impact on our operating results. Current economic conditions have resulted in a decline in the forward price curve for energy and decreased commodity-trading margins. In addition, certain operating costs, such as insurance and security, have increased due to the economy, terrorist activity and the threat of war. Management cannot predict the impact of a continued economic slowdown, fluctuating energy prices, war or the threat of war.

However, we could experience a material adverse impact to our results of operations, future growth or ability to raise capital from a weakened economy or war.

Sales Growth In addition to weather impacts, customer sales levels in our 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 1.6 percent in the first nine months of 2003 compared with the first nine months of 2002, 1.8 percent in 2002 compared with 2001, and 1.0 percent in 2001 compared with 2000. Weather-normalized sales growth for firm gas utility customers was estimated to be 3.8 percent in the first nine months of 2003 compared with the first nine months of 2002, approximately the same in 2002 compared with 2001, and 2.6 percent in 2001 compared with 2000. We are projecting that weather-normalized sales growth in 2003 compared with 2002 will be 1.8 percent for retail electric utility customers and 2.9 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 over the past few years has been significant as utilities combine to capture economies of scale or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide nondiscriminatory access to the use of their transmission systems.

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

Some states had begun to allow retail customers to choose their electricity supplier, and many other states were considering retail access proposals. However, the experience of the State of California in instituting competition, as well as the bankruptcy filing of Enron Corporation in 2001, have caused indefinite delays in most industry restructuring.

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We cannot predict the outcome of restructuring proceedings in the electric utility jurisdictions we serve at this time. The resolution of these matters may have a significant impact on our financial position, results of operations and cash flows.

California Power Market NRG operates in the wholesale power market in California. See Note 18 to the audited consolidated financial statements and Note 8 to the interim consolidated financial statements for a description of lawsuits against NRG and other power producers and marketers involving the California electricity markets. We and NRG have fully reserved for our uncollected receivables related to the California power market.

Critical Accounting Policies Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles (GAAP) requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the 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 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 our financial condition and results, and that require management s most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policy	Judgments/Uncertainties Affecting Application	See Additional Discussion At
Asset Valuation NRG Seren Argentina	Regional economic conditions affecting asset operation, market prices and related cash flows Foreign currency valuation changes Regulatory and political environments and requirements Levels of future market penetration and customer growth	Management s Discussion and Analysis: Results of Operations Management s Discussion and Analysis: Factors Affecting Results of Operations Impacts of NRG Financial Difficulties Impact of Other Nonregulated Investments Notes to Audited Consolidated Financial Statements Notes 2, 3 and 18
NRG Financial Restructuring	Terms negotiated to settle NRG s obligations to its creditors Ownership interest in and control of NRG, and related ability to continue consolidating NRG as a subsidiary Impacts of court decisions in future bankruptcy proceedings, including any obligations of Xcel Energy	Management s Discussion and Analysis: Liquidity and Capital Resources NRG Financial Issues Xcel Energy Impacts Notes to Audited Consolidated Financial Statements Notes 4 and 18
Income Tax Accruals	Application of tax statutes and regulations to transactions Anticipated future decisions of tax authorities Ability of tax authority decisions/ positions to withstand legal challenges and appeals Ability to realize tax benefits through carrybacks to prior periods or carryovers to future periods	Management s Discussion and Analysis: Factors Affecting Results of Operations Tax Matters Notes to Audited Consolidated Financial Statements Notes 1, 11 and 18

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Accounting Policy	Judgments/Uncertainties Affecting Application	See Additional Discussion At
Benefit Plan Accounting	Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition Interest rates used in valuing benefit obligation Actuarial period selected to recognize deferred investment gains and losses	Management s Discussion and Analysis: Factors Affecting Results of Operations Pension Plan Costs and Assumptions Notes to Audited Consolidated Financial Statements Notes 1 and 13
Regulatory Mechanisms and Cost Recovery	External regulator decisions, requirements and regulatory environment Anticipated future regulatory decisions and their impact Impact of deregulation and competition on ratemaking process and ability to recover costs	Management s Discussion and Analysis: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to Audited Consolidated Financial Statements Notes 1, 18 and 20
Environmental Issues	Approved methods for cleanup Responsible party determination Governmental regulations and standards Results of ongoing research and development regarding environmental impacts	Management s Discussion and Analysis: Factors Affecting Results of Operations Environmental Matters Notes to Audited Consolidated Financial Statements Notes 1 and 18
Uncollectible Receivables	Economic conditions affecting customers, suppliers and market prices Regulatory environment and impact of cost recovery constraints on customer financial condition Outcome of litigation and regulatory proceedings	Management s Discussion and Analysis: Factors Affecting Results of Operations California Power Market Notes to Audited Consolidated Financial Statements Notes 1 and 18
Nuclear Plant Decommissioning and Cost Recovery	Costs of future decommissioning Availability of facilities for waste disposal Approved methods for waste disposal Useful lives of nuclear power plants Future recovery of plant investment and decommissioning costs	Notes to Audited Consolidated Financial Statements Notes 1, 18 and 19

Pension Plan Costs and Assumptions Our 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 volatility of varying investment performance over time. Note 13 to the audited consolidated financial statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

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

We base our investment return assumption on expected long-term performance for each of the investment types included in our pension asset portfolio. These include equity investments, such as corporate common stocks; fixed-income investments, such as corporate bonds; and U.S. Treasury securities and non-traditional investments, such as timber or real estate partnerships. In reaching a return assumption, we consider the actual historical returns achieved by our asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts in the marketplace. The

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historical weighted average annual return for the past 20 years for our portfolio of pension investments is 12.6 percent, in excess of the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long-term. The target and 2002 mix of assets among these portfolio components is discussed in Note 13 to the audited consolidated financial statements. Our portfolio is heavily weighted toward equity securities, and includes non-traditional investments that can provide a higher than average return. However, as is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels actually achieved by pension assets in any year. We lowered the 2003 pension investment return assumptions to reflect changing expectations of investment experts in the marketplace.

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

We base our discount rate assumption on benchmark interest rates quoted by an established credit rating agency, Moody s Investors Services, Inc. (Moody s), and have consistently benchmarked the interest rate used to derive the discount rate to the movements in 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 December 31, 2002, the annualized Moody s Aa index rate, roughly in the middle of the AAA and BAA range, was 6.63 percent, which when rounded to the nearest quarter-percent rate, as is our policy, resulted in our 6.75 percent pension discount rate at year-end 2002. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2003 pension cost determinations.

If we 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 us for financial reporting purposes:

a 1 percent higher rate of return, 10.25 percent, would decrease 2003 pension costs by $22 million;

a 1 percent lower rate of return, 8.25 percent, would increase 2003 pension costs by $22 million;

a 1 percent higher discount rate, 7.75 percent, would decrease 2003 pension costs by $8 million; and

a 1 percent lower discount rate, 5.75 percent, would increase 2003 pension costs by $12 million.

Alternative assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in recent years for our pension plans, and do not require funding in 2003. Assuming future asset return levels equal the actuarial assumption of 9.25 percent for the years 2003-2005, then under current funding regulations we project that no cash funding would be required for 2004, $35 million in funding would be required for 2005, and $54 million in funding would be required for 2006. Actual performance can affect these funding requirements significantly. If the actual return level is 0 percent in 2003 and 2004, which assumes a continued downturn in the financial markets, and 9.25 percent in 2005, then the 2004 cash-funding requirement would still be zero. However, the 2005 funding requirement would increase to $60 million, and 2006 funding required would be $70 million. Current funding regulations

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are under legislative review in 2003, and if not retained in their current form, could change these funding requirements materially.

In April 2003, we amended certain of our retirement plans to provide the same level of benefits to all non-bargaining employees of our utility and service company operations. While this change did not have a material impact on 2003 costs for the affected pension and retiree health plans, the increased obligations resulting from the plan amendment did create a minimum pension liability which was recorded in the second quarter of 2003.

Regulation We are a registered holding company under PUHCA. As a result, we, our utility subsidiaries and certain of our nonutility subsidiaries are subject to extensive regulation by the SEC under 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, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. See further discussion of financing restrictions under Liquidity and Capital Resources.

The electric and natural gas rates charged to customers of our 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. We request 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 our financial results. In addition to changes in operating costs, other factors affecting rate filings are sales growth, conservation and demand-side management efforts and the cost of capital.

Most of the retail rate schedules for our utility subsidiaries provide for periodic adjustments to billings and revenues to allow for recovery of changes in the cost of fuel for electric generation, purchased energy, purchased natural gas and, in Minnesota and Colorado, conservation and energy management program costs. In Minnesota and Colorado, changes in electric capacity costs currently 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 (IAC) mechanism in effect for 2003 under which it will recover 100 percent of prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates during 2003. This clause is projected to recover energy costs totaling approximately $216 million in 2003. Beginning in January 2004 through 2006, PSCo will implement a new Electric Commodity Adjustment (ECA) clause that provides for the sharing of costs over or under an allowed ECA formula rate up to a $11.25 million cap.

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, we may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from our balance sheet. Such changes could have a material adverse effect on our results of operations in the period the write-off is recorded.

At September 30, 2003, we reported on our balance sheet regulatory assets of approximately $584 million and regulatory liabilities of approximately $335 million that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. We currently do not expect to write off any stranded costs unless market price levels change or cost levels increase above market price levels. See Notes 1 and 20 to the audited consolidated financial statements for further discussion of regulatory deferrals.

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

As part of the merger approval process in Colorado, PSCo agreed to:

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

As part of the merger approval process in Minnesota, NSP-Minnesota agreed to:

- reduce its Minnesota electric rates by $10 million annually through 2005;
- not increase its electric rates through 2005, except under limited circumstances;
- not seek recovery of certain merger costs from customers; and
- meet various quality standards.

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

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

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

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

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

- an annual electric earnings test with the sharing between customers and shareholders of earnings in excess of the following limits:
  - all earnings above 10.50 percent return on equity for 2002;
  - no earnings sharing for 2003; and
  - an annual electric earnings test with the sharing of earnings in excess of 10.75 percent for 2004 through 2006;
- an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2006; and
- a gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to gas leak repair time and customer service through 2007.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the earnings test. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually. During 2002, PSCo filed that its electric department earnings were below the 10.5 percent return on equity threshold. PSCo has estimated no customer refund obligation for 2002 under the earnings test, the electric QSP or the gas QSP. PSCo has estimated no customer refund obligation for 2001 under the earnings test. In the 2001 proceeding, the Office of Consumer Counsel has proposed that the $10.9 million gain on the sale of Boulder Hydroelectric Project be excluded from 2001 earnings and that possible refund of the gain be addressed in a separate proceeding. In the 2002 proceeding, the CPUC has ordered a hearing to consider the effect on PSCo s capital structure of its $600 million debt issuance in September 2002. Because no party has yet filed testimony in the 2002 proceeding, we are unable to predict the effect, if any, this proceeding may have with respect to the 2002 earnings test calculation. A final decision on both proceedings in pending. PSCo does not expect to achieve certain performance targets under the electric QSP for 2003. PSCo has recorded an estimated liability of $6.4 million relating to the electric reliability and customer complaint measures.

On October 3, 2003, PSCo filed an application to put into effect a Purchased Capacity Cost Adjustment (PCCA) mechanism effective March 1, 2004 that would allow it to recover 100 percent of its incremental purchased capacity costs over the level of these costs in base rates. As part of the application, in consideration for approval of the PCCA, PSCo has proposed to modify the PBRP for 2004 through 2006 to provide that 100 percent of any earnings in excess of 10.75 percent return on equity to be returned to customers.

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 between PSCo and all but one of the intervenors was executed and filed with the CPUC, which addressed all significant issues in the rate case. In summary, the settlement agreement, among other things, provides for:

- annual base rate decreases 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 recovers 100 percent of prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates during 2003. This clause is projected to recover energy costs totaling approximately $216 million in 2003;
- a new electric commodity adjustment clause (ECA) for 2004-2006, 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.

In June 2003, the CPUC issued its initial written order approving the settlement agreement. The new rates were effective July 1, 2003. The CPUC issued its final decision in the rate case on August 8, 2003. PSCo expects to file the rate design portion of the case on or before December 8, 2003.

Fuel Adjustment Clause Proceedings Certain of PSCo s wholesale power customers filed complaints with the FERC in 2002 alleging that PSCo had been improperly collecting certain fuel and purchased energy costs through the wholesale fuel cost adjustment clause included in their rates. The FERC consolidated these complaints and set them for hearing. The complainants filed initial testimony in late April 2003 claiming the improper inclusion of fuel and purchased energy costs in the range of $40 million to $50 million related to the periods 1996 through 2002. PSCo submitted answering testimony in June 2003. In rebuttal testimony the complainants filed on August 1, 2003, they quantified their claims at approximately $30 million. During the week of August 18, 2003, PSCo reached agreements in principle with all of the complainants under which such claims, as well as issues those customers had raised in response to PSCo s wholesale general rate case filing discussed elsewhere in this prospectus, were compromised and settled. Under the settlement agreements PSCo will make cash payments or billing credits to certain of the complaining customers totaling approximately $1.5 million. The settlements also provide for revisions to the base demand and energy rate filed in the wholesale electric rate case. PSCo and the other parties are negotiating the detailed settlement provisions which are subject to FERC approval.

PSCo had a retail incentive cost adjustment (ICA) cost recovery mechanism in place for periods prior to calendar 2003. The CPUC conducted a proceeding to review and approve the incurred and recoverable 2001 costs under the ICA. In April 2003, the CPUC Staff and an intervenor filed testimony recommending disallowance of fuel and purchased energy costs, which, if granted, would result in a $30 million reduction in recoverable 2001 ICA costs. On July 10, 2003, a stipulation and settlement agreement was filed with the CPUC, which resolved all issues. Under the stipulation and settlement agreement, the recoverable costs under the ICA for the years 2001 and 2002 will be reduced by approximately $1.6 million. Additional evaluation of 2002 recoverable ICA costs will be conducted in a future CPUC proceeding. The resulting impact on the reset of the allowed cost recovery and cost sharing under the ICA for 2002 was not significant. In addition, the stipulation and settlement agreement provides for a prospective rate design adjustment related to the maximum allowable natural gas hedging costs that will be a part of the electric commodity adjustment for 2004 and is expected to reduce 2004 rates by an estimated $4.6 million. The stipulation and settlement agreement was approved by the CPUC in September, 2003.

At September 30, 2003, PSCo has recorded its deferred fuel and purchased energy costs based on the expected rate recovery of its costs as filed in the above rate proceedings, without the adjustments proposed by various parties. Pending the outcome of these regulatory proceedings, we cannot at this time determine whether any customer refunds or disallowances of PSCo s deferred costs will be required other than as discussed above.

Tax Matters As discussed further in Note 18 to the audited consolidated financial statements, 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, we received a technical advice memorandum from the IRS national office that communicated a position adverse to PSRI. Consequently, the IRS examination division has disallowed the interest expense deductions for the tax years 1993 through 1997.

We intend to challenge the IRS determination, which could require several years to reach final resolution. Because it is our position that the IRS determination is not supported by the tax law, PSRI has not recorded any provision for income tax or interest expense related to this matter and continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. However, defense of our position may require significant cash outlays on a temporary basis if refund litigation is pursued in United States District Court.

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

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

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

$74 million in the six months ended June 30, 2003;

$149 million in 2002;

$146 million in 2001; and

$144 million in 2000.

We expect to expense an average of approximately $160 million per year from 2003 through 2007 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

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

$36.3 million in the six months ended June 30, 2003;

$108 million in 2002;

$136 million in 2001; and

$57 million in 2000.

Our regulated utilities expect to incur approximately $7.7 million in capital expenditures for compliance with environmental regulations during the last six months of 2003 and approximately $948 million during the period from 2003 through 2007. Most of the costs are related to modifications to reduce the emissions of NSP-Minnesota s generating plants located in the Minneapolis-St. Paul metropolitan area. See Notes 18 and 19 to the audited consolidated financial statements and Note 8 to the interim consolidated financial statements for further discussion of our environmental contingencies.

NRG expects to incur as much as $145 million in capital expenditures during the period from 2003 through 2007 to address conditions that existed when it acquired facilities, and to comply with new regulations.

Impact of Other Nonregulated Investments Our investments in nonregulated operations have had a significant impact on our results of operations. We do not expect to continue investing in nonregulated domestic and international power production projects through NRG, but may continue investing in construction projects through Utility Engineering. Our nonregulated businesses may carry a higher level of risk than its traditional utility businesses due to a number of factors, including:

competition, operating risks, dependence on certain suppliers and customers, and domestic and foreign environmental and energy regulations;

partnership and government actions and foreign government, political, economic and currency risks; and

development risks, including uncertainties prior to final legal closing.

Our earnings from nonregulated subsidiaries, other than NRG, also include investments in international projects, primarily in Argentina, through Xcel Energy International, and broadband communications systems through Seren. Management currently intends to hold and operate these investments, but is evaluating their strategic fit in our business portfolio. As of September 30, 2003, our investment in Seren was approximately $266 million. Seren had capitalized $319 million for plant in service and had incurred another $16 million for construction work in progress for these systems at September 30, 2003. Xcel Energy International s gross investment in Argentina, excluding unrealized currency translation losses of approximately $58 million, was $121 million at September 30, 2003. Given the political and economic climate in Argentina, we continue to closely monitor the investment for asset impairment. Currently, management believes that no impairment exists in addition to what was recognized in 2002, as previously discussed.

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

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

Accounting Changes

SFAS No. 150 In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150 Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. SFAS No. 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity, including:

instruments that represent, or are indexed to, an obligation to buy back the issuer s shares, regardless whether the instrument is settled on a net-cash or gross physical basis;

mandatorily redeemable equity instruments;

written options that give the counterparty the right to require the issuer to buy back shares; and

forward contracts that require the issuer to purchase shares.

In November 2003, the FASB posted a staff position, which delayed the implementation of SFAS No. 150 indefinitely. On September 30, 2003, SPS had a special purpose subsidiary trust with outstanding mandatorily redeemable preferred securities of $100 million consolidated in our consolidated balance sheets. These securities were redeemed on October 15, 2003. NSP-Minnesota redeemed its $200 million of Trust Originated Preferred Securities on July 31, 2003, and SFAS No. 150 will not affect such securities.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46 requiring an enterprise s consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, consolidation has been required for only 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 that enterprise has a controlling financial interest. As a result, we expect that we will be required to consolidate all or a portion of our affordable housing

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investments made through Eloigne, which currently are accounted for under the equity method. Additionally, we are evaluating two other arrangements based on criteria in FIN No. 46, and it is likely that these arrangements will require consolidation.

As of September 30, 2003, the assets of the affordable housing investments were approximately $146 million and long-term liabilities were approximately $78 million. Currently, investments of $61 million are reflected as a component of investments in unconsolidated affiliates in the December 31, 2002 consolidated balance sheet. FIN No. 46 requires that for entities to be consolidated, the entities assets be initially recorded at their carrying amounts at the date the new requirement first applies. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to our 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. We plan to adopt FIN No. 46 when required in the fourth quarter of 2003. The impact of consolidating these entities is not expected to have a material impact on net income.

SFAS No. 143 We adopted Statement of Financial Accounting Standard (SFAS) No. 143 Accounting for Asset Retirement Obligations effective January 1, 2003. As required by SFAS No. 143, future plant decommissioning obligations were recorded as a liability at fair value as of January 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 our utility subsidiaries is described below. 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 Accounting for the Effects of Certain Types of Regulation.

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 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 through June of 2000.

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

	Increase (decrease) in:		
	Plant Assets	Regulatory Assets	Long-Term Liabilities
		(Thousands of dollars)	
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	
Reclassify pre-adoption accumulated depreciation approved by regulators	662,411	(662,411)	
Net impact of SFAS No. 143 on balance sheet	$ 682,497	$ 179,871	$ 862,368

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A reconciliation of the beginning and ending aggregate carrying amount of NSP-Minnesota s asset retirement obligations recorded under SFAS No. 143 is shown in the table below for the nine months ended September 30, 2003.

	Beginning Balance Jan. 1, 2003	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance September 30, 2003
	(Thousands of dollars)					
Steam plant retirement	$ 2,725	$	$	$ 101	$	$ 2,826
Nuclear plant decommissioning	859,643	—	—	42,380	103,685	1,005,708
Total liability	$ 862,368	$	$	$ 42,481	$ 103,685	$ 1,008,534

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 recognized 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 in accumulated depreciation for these plants prior to the implementation of SFAS No. 143. The net regulatory asset of $180 million at January 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. We expect this regulatory asset to reverse over time since the costs to be accrued under SFAS No. 143 are 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 Minnesota Public Utilities Commission (MPUC) in August 2003. The revised estimates resulted in an increase of $104 million to both the regulatory asset and the long-term liability, 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, as discussed in Note 14 to the interim consolidated financial statements.

The pro forma liability to reflect amounts as if SFAS No. 143 had been applied as of December 31, 2002, was $862 million, the same as the January 1, 2003, amounts discussed previously. The pro forma liability to reflect adoption of SFAS No. 143 as of January 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 years ended December 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 us 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 s assets legally restricted for purposes of settling the nuclear asset retirement obligations is $844 million as of September 30, 2003, including external nuclear decommissioning investment funds and internally funded amounts.

The adoption of SFAS No. 143 in 2003 also affects our accrued plant removal costs for other generation, transmission and distribution facilities for our utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a GAAP liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical

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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 estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 71 that are accrued in accumulated depreciation, are as follows at January 1, 2003:

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

SFAS No. 145 In April 2002, the FASB issued SFAS No. 145 Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, which supersedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things. We adopted SFAS No. 145 in July 2003. Adoption of SFAS No. 145 may affect the recognition of impacts from NRG s financial improvement and restructuring plan if existing debt agreements are ultimately renegotiated and NRG is reconsolidated with us. Other impacts of SFAS No. 145 are not material to us.

Pending Accounting Changes

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

SFAS No. 148 In December 2002, the FASB issued SFAS No. 148 Accounting for Stock-Based Compensation Transition and Disclosure, amending 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 148 to earnings and earnings per share is immaterial. We continue to account for our stock-based compensation plans under Accounting Principles Board (APB) Opinion No. 25 Accounting for Stock Issued to Employees, and do not plan at this time to adopt the voluntary provisions of SFAS No. 148. Even with full dilutive effects of stock equivalents, the impact of application of SFAS No. 148 would be immaterial to our financial results.

SFAS No. 149 In April 2003, the FASB issued SFAS No. 149 Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS No. 149), which amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies the discussion around initial net investment, clarifies when a derivative contains a financing component and amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45. In addition, SFAS No. 149 also incorporates certain implementation issues of a derivative implementation group. The provisions of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003.

SFAS No. 133 Implementation Issue No. C20 In June 2003, for purposes of determining the applicability of the normal purchases and normal sales scope exception, the FASB issued SFAS No. 133 Implementation Issue No. C20 as supplemental guidance to SFAS No. 133 Implementation Issue No. C11.

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The effective date of the implementation guidance of Issue No. C20 for us is during the fourth quarter of 2003. We are currently in the process of reviewing and interpreting this guidance and do not anticipate any material adverse financial impact due to the implementation of Issue No. C20 guidance as a result of our ability to recover prudently-incurred purchased capacity costs from customers.

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

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

Derivatives, Risk Management and Market Risk

Business and Operational Risk We and our subsidiaries are exposed to commodity price risk in our 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, we and our subsidiaries have limited exposure to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, electric energy and natural gas expenses are recovered based on fixed price limits or under established sharing mechanisms.

We manage 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. Our risk management policy allows us to manage the market price risk within each rate regulated operation to the extent such exposure exists. Management is limited under the policy to enter into only transactions that manage market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas and electricity we provide to our retail customers even though the regulatory jurisdiction 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.

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

We are exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from our equity method investments that own electric operations. We manage this market price risk through involvement with the management committee or board of directors of each of these ventures. Policies are adopted by the ventures as necessary and mandated by the equity owners.

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

At September 30, 2003 and December 31, 2002 and 2001, a 100 basis point change in the benchmark rate on our variable debt would impact net income by approximately $1.9 million, $52.2 million and $29.9 million, respectively. See Note 16 to the audited consolidated financial statements and Note 10 to the interim consolidated financial statements for a discussion of our and our subsidiaries interest rate swaps.

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

As discussed in Note 21 to the audited consolidated financial statements, we have substantial investments in foreign projects, through NRG and other subsidiaries, creating exposure to currency translation risk. Cumulative translation adjustments, included in the consolidated statement of stockholders equity as Accumulated Other Comprehensive Income, experienced to date have been material and may continue to occur at levels significant to our financial position. As of December 31, 2002, NRG had two foreign currency exchange contracts with notional amounts of $3.0 million. If the contracts had been discontinued on December 31, 2002, NRG would have owed the counterparties approximately $0.3 million.

As of September 30, 2003, NRG had no foreign currency exchange contracts outstanding.

Financial Market Risk We and our subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. Our risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by our risk management committee, which is made up of management personnel not involved in the trading operations.

We and our subsidiaries use a value-at-risk (VaR) model to assess the market risk of our fixed price purchase and sales commitments, physical forward contracts and commodity derivative instruments. VaR for commodity contracts, assuming a five-day holding period for electricity and a two-day holding period for natural gas, for the three months ended September 30, 2003 were as follows:

	Period Ended September 30, 2003	Change From Period Ended June 30, 2003	VaR Limit	Average	High	Low
		(Millions of dollars)				
Electric Commodity Trading(1)	$0.82	$(0.08)	$6.0	$0.75	$1.48	$0.36
e prime Inc.	0.01	(0.00)	2.0	0.01	0.03	0.00
e prime Energy Marketing Inc.	0.16	0.09	2.0	0.12	0.21	0.05
XERS Inc.	0.00	(0.13)	2.0	0.02	0.12	0.00

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

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As of December 31, 2002, the calculated VaRs were:

Operations	Year ended Dec. 31, 2002	During 2002 Average	High	Low
		(Millions of dollars)		
Electric Commodity Trading	0.29	0.62	3.39	0.01
Natural Gas Commodity Trading	0.11	0.35	1.09	0.09
Natural Gas Retail Marketing	0.54	0.47	0.92	0.32
NRG Power Marketing(a)	118.60	76.20	124.40	42.00

(a) NRG VaR is an undiversified VaR.

As of December 31, 2001, the calculated VaRs were:

Operations	Year ended Dec. 31, 2001	During 2001 Average	High	Low
		(Millions of dollars)		
Electric Commodity Trading	0.52	1.71	7.37	0.16
Natural Gas Commodity Trading	0.16	0.15	0.52	0.01
Natural Gas Retail Marketing	0.69	0.39	0.94	0.13
NRG Power Marketing	71.70	78.80	126.60	58.60

In 2001, we changed our holding period for measuring VaR from electricity trading activity from 21 days to two to five days. Our revised holding periods are generally consistent with current industry standard practice.

Energy Trading and Hedging Activities We and our subsidiaries engage in energy trading activities that are accounted for in accordance with SFAS No. 133, as amended. We and our subsidiaries make wholesale purchases and sales of electric, natural gas and related energy trading products in order to optimize the value of our electric generating facilities and retail supply contracts. We also engage in a limited number of wholesale commodity transactions. We utilize forward contracts for the purchase and sale of electricity and capacity, over-the-counter swap contracts, exchange-traded natural gas futures and options, transmission contracts, natural gas transportation contracts and other physical and financial contracts.

For the period ended September 30, 2003, these contracts, with the exception of transmission and natural gas transportation contracts, which meet the definition of a derivative in accordance with SFAS No. 133, were marked to market. Changes in fair value of energy trading contracts that do not qualify for hedge accounting treatment are recorded in income in the reporting period in which they occur.

The changes to the fair value of the energy trading and hedging contracts for the nine months ended September 30, 2003 and 2002 were as follows:

	Nine months ended Sept. 30,* 2003	2002
	(Millions of Dollars)	
Fair value of contracts outstanding at Jan. 1	$ 7.8	$ 17.9
Contracts realized or otherwise settled during the period	(15.9)	(11.9)
Fair value of trading contract additions and charges during the period	19.3	9.3

Fair value of contracts outstanding at Sept. 30	$ 11.2	$ 15.3

* Excludes NRG.

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As of September 30, 2003, the sources of fair value of the energy trading and hedging net assets were as follows:

Trading Contracts

	Futures/ Forwards					
	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
	(Thousands of Dollars)					
NSP-Minnesota	1	$ (306)				$ (306)
	2	9,745				9,745
PSCo.	1	(440)				(440)
	2	1,442				1,442
e prime Inc.	1	685				685
	2	50				50
Total Futures/ Forwards Fair Value		$11,176				$11,176

	Options					
	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
	(Thousands of Dollars)					
PSCo.	2	$ 12				$ 12
e prime Inc.	2	10				10
Total Options Fair Value		$ 22				$ 22

Hedge Contracts

	Futures/ Forwards					
	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
	(Thousands of Dollars)					
NSP-Minnesota	2	$ 1,532				$ 1,532
PSCo.	2	240				240
e prime Inc.	1	(132)				(132)
e prime Energy Mktg, Inc.	1	(2,262)	(625)			(2,887)
XERS Inc.	1	(324)	10			(314)
Total Futures/ Forwards Fair Value		$ (946)	$(615)			$(1,561)

	Options					
	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
		(Thousands of Dollars)				
NSP-Minnesota	2	$ (6,788)				$ (6,788)
NSP-Wisconsin	2	(1,106)				(1,106)
PSCo.	2	(22,967)	695			(22,272)
Total Options Fair Value		$ (30,861)	695	—	—	$ (30,166)

(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 deals are included for PSCo, NSP-Minnesota and NSP-Wisconsin. Normal purchases and sales deals have been excluded.

As of December 31, 2002, the future maturities of our trading contracts were as follows:

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

Credit Risk In addition to the risks discussed previously, we and our subsidiaries are exposed to credit risk in our risk management activities. Credit risk relates to the risk of loss resulting from the non-performance by a counterparty of its contractual obligations. As we continue to expand our natural gas and power marketing and trading activities, exposure to credit risk and counterparty default may increase. We and our subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

We and our subsidiaries conduct standard credit reviews for all counterparties. We employ 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.

For more information regarding derivative valuation and the financial impacts, see Note 10 to the interim consolidated financial statements.

Liquidity and Capital Resources

Cash Flows

	Nine months ended September 30,		Year ended December 31,		
	2003	2002	2002	2001	2000
			(Millions of dollars)		
Net cash provided by operating activities	$1,003	$1,499	$1,715	$1,584	$1,408

Cash provided by operating activities decreased for the first nine months of 2003, compared with the first nine months of 2002. The decrease was primarily due to the deconsolidation of NRG, which resulted in no operating cash flows in 2003 compared with approximately $400 million in 2002. In addition, cash flows were lower in 2003 due to higher cash outlays for deferred energy costs in 2003, which will be recovered in future periods, and to the higher collection of prior year unbilled revenue in 2002. Cash provided by operating activities increased during 2002, compared with 2001, primarily due to NRG s efforts to conserve cash by deferring the payment of interest payments and managing its cash flows more closely. NRG s accrued interest costs rose by nearly $200 million in 2002 compared to year-end 2001 levels. In addition, regulated utility operating cash flows increased in 2002 due to lower 2002 receivables and unbilled revenues, reflecting

collections of higher year-end 2001 amounts. Cash provided by operating activities increased during 2001, compared with 2000, primarily due to the higher net income, depreciation and improved working capital.

	Nine months ended September 30,		Year ended December 31,		
	2003	2002	2002	2001	2000
	(Millions of dollars)				
Net cash used in investing activities	$(575)	$(2,302)	$(2,718)	$(5,168)	$(3,347)

Cash used in investing activities decreased for the first nine months of 2003, compared with the first nine months of 2002. The decrease is largely due to significant nonregulated capital expenditures and equity investments by NRG in 2002, compared with none in 2003 as a result of the deconsolidation of NRG. In addition, 2003 net cash outflows were partially offset by the proceeds from the sale of Viking Gas in January 2003. Cash used in investing activities decreased during 2002, compared with 2001, primarily due to lower levels of nonregulated capital expenditures as a result of NRG terminating its acquisition program due to its financial difficulties. Such nonregulated expenditures decreased $2.8 billion in 2002 due mainly to NRG asset acquisitions in 2001 that did not recur in 2002. Cash used in investing activities increased during 2001, compared with 2000, primarily due to increased levels of nonregulated capital expenditures and asset acquisitions, primarily at NRG. The increase was partially offset by our sale of most of our investment in Yorkshire Power.

	Nine months ended September 30,		Year ended December 31,		
	2003	2002	2002	2001	2000
	(Millions of dollars)				
Net cash (used in) provided by financing activities	$(232)	$1,785	$1,580	$3,713	$2,016

Cash flows related to financing activities decreased from net inflows for the first nine months of 2002 to net outflows in the first nine months of 2003. The decrease is largely due to significant financing requirements for NRG in 2002 compared with none in 2003 as a result of the deconsolidation of NRG. Cash provided by financing activities decreased during 2002, compared with 2001, primarily due to lower NRG capital requirements and constraints on NRG s ability to access the capital market due to its financial difficulties, as discussed previously. NRG s cash provided from financing activities declined by $2.7 billion in 2002, compared with 2001. Cash provided by financing activities increased during 2001, compared with 2000, primarily due to increased short-term borrowings and net long-term debt issuances, mainly to fund NRG acquisitions.

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

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Capital Requirements

Utility Capital Expenditures, Nonregulated Investments and Long-term Debt Obligations The estimated cost as of June 30, 2003 of our and our subsidiaries capital expenditure programs, excluding NRG, and other capital requirements for the years 2003, 2004 and 2005 are shown in the table below.

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

The capital expenditure forecast for 2004 includes new steam generators at the Prairie Island nuclear plant. The capital expenditure forecast also includes the early stages of the costs related to modifications to reduce the emissions of NSP-Minnesota s generating plants located in the Minneapolis and St. Paul metropolitan area. This project is expected to cost approximately $1.1 billion with major construction starting in 2005 and finishing in 2009.

Our capital expenditure programs 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 our long-term energy needs. In addition, our ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission-control equipment may impact actual capital requirements. For more information, see Notes 4 and 18 to the audited consolidated financial statements and Note 8 to the interim consolidated financial statements.

Our investment in exempt wholesale generators and foreign utility companies, which includes NRG and other subsidiaries of us, is currently limited to 100 percent of consolidated retained earnings, as a result of PUHCA restrictions. At September 30, 2003, such investments exceeded consolidated retained earnings. As a result of impairment charges recorded by NRG in 2002, our consolidated retained earnings have been reduced by more than $2.6 billion. Thus, at this time, we have no capacity to make any additional investments in exempt wholesale generators and foreign utility companies without further authorization from the SEC.

Contractual Obligations and Other Commitments We have a variety of contractual obligations and other commercial commitments that represent prospective requirements in addition to our capital expenditure programs. The table below is a summarized table of contractual obligations as of June 30, 2003. See additional

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discussion in the Consolidated Statements of Capitalization and in Notes 5, 6, 7, 16 and 18 to the audited consolidated financial statements and Notes 8 and 9 to the interim consolidated financial statements.

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
			(Thousands of dollars)		
Long-term debt	$ 5,690,479	$ 240,533	$ 369,021	$ 872,997	$ 4,207,928
Capital lease obligations	110,092	7,467	14,148	13,164	75,313
Operating leases(a)	357,103	67,128	109,311	92,704	87,960
Unconditional purchase obligations	11,848,211	1,129,164	2,445,378	2,115,162	6,158,507
Other long-term obligations	529,505	44,745	66,257	44,224	374,279
Short-term debt	744,556	744,556			
Total contractual cash obligations	$19,279,946	$2,233,593	$3,004,115	$3,138,251	$10,903,987

(a) Under some leases, we would have to sell or purchase the property that we lease if we chose to terminate before the scheduled lease expiration date. Most of our railcar, vehicle and equipment, and aircraft leases have these terms. We would then own the equipment and could continue to use it in the normal course of business or sell the equipment. At September 30, 2003, the amount that we would have to pay if we chose to terminate these leases was approximately $147 million.

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

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. As a result of additional write-downs at NRG, our retained earnings were a deficit of approximately $245 million on June 30, 2003.

In May 2003, we received authorization from the SEC to pay an aggregate amount of $152 million of common and preferred dividends out of capital and unearned surplus. We used this authorization to declare and pay approximately $150 million for our first and second quarter dividends in 2003. In addition, the SEC reserved jurisdiction over our request to pay an additional $108 million of common and preferred dividends out of capital and unearned surplus until September 30, 2003.

On September 12, 2003, we requested that the SEC release jurisdiction over the payment of common and preferred dividends out of capital and unearned surplus for the third quarter of 2003. No such authorization has yet been received. On September 25, 2003, we announced that our normal third quarter dividend would be delayed. On September 30, 2003, our retained earnings were approximately $43 million. On October 22, 2003, we declared third quarter dividends on our preferred stock, based on the third quarter results, which indicated sufficient retained earnings were available to do so. The dividends were paid on November 10, 2003 to preferred stock shareholders of record on October 31, 2003. Assuming that the NRG plan of reorganization is approved by NRG s creditors in December 2003 as expected and earnings for 2003 are as anticipated, we currently expect to have retained earnings sufficiently positive before the end of 2003 to pay the third quarter common stock dividend in December as well as declare the fourth quarter common and preferred dividends (normally payable in January 2004). We intend to make every effort to pay the full annual dividend of 75 cents per share during 2003 on our common stock and any accrued dividends on our preferred stock.

Our Articles of Incorporation place restrictions on the amount of common stock dividends we can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if our 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 (1) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at September 30, 2003, was 40 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

Capital Sources

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

Registered holding companies and certain of their subsidiaries, including us and our 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 we do not qualify for any of the main exemptive rules, we sought and received financing authority from the SEC under PUHCA for various financing arrangements. Our current financing authority permits us, 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. We have issued $2 billion of long-term debt and common stock. As discussed above, our ability to issue securities under this authority is subject to a number of conditions, including that all of our rated securities (other than our preferred stock) are rated investment grade by at least one nationally recognized rating agency.

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

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

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. These factors are evaluated by credit rating agencies that review our and our subsidiary operations on an ongoing basis. NRG s credit situation has affected our credit ratings and access to short-term funding. As a result of a decline in our credit ratings in 2002, we have been unable to utilize the commercial paper market to satisfy any short-term funding needs. For additional information on our short-term borrowing arrangements, see Note 5 to the audited consolidated financial statements and Note 9 to the interim consolidated financial statements.

Access to reasonably priced capital markets is also dependent in part on credit agency reviews. In 2002, our credit ratings and those of our subsidiaries were adversely affected by NRG s credit contingencies, despite what management believes is a reasonable separation of NRG s operations and credit risk from our utility operations and corporate financing activities. These ratings reflect the views of Moody s and Standard & Poor s. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or

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withdrawal at any time by the rating company. As of September 30, 2003, the rating companies assigned the following credit ratings 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
NRG	Corporate Credit Rating	Caa3***	D***

* Stable outlook

** CreditWatch positive

*** Below investment grade

Moody s and Standard & Poor s each provide long-term and short term credit ratings. Both rating agencies distinguish between investment grade and non-investment grade ratings, and within these two categories between superior, excellent, good and adequate, which are conside investment grade, and may be adequate, vulnerable, extremely vulnerable and default, which are considered non-investment grade. Moody s issues its ratings in the form of letter combinations ranging from Aaa through D, with Baa3 being the lowest investment grade rating and Ba1 being the highest non-investment grade rating. Standard & Poor s provides its ratings in form of letter combinations ranging from AAA through D, with BBB- being the lowest investment grade rating and BB+ being the highest non-investment grade rating. Furthermore, Standard & Poor s provides short-term ratings ranging from A-1, which is considered strong, to D, which stands for default. Moody s provides three short-term ratings ranging from P-1, which stands for a superior rating, to P-3, which stands for an acceptable rating.

NRG s access to short-term capital is currently non-existent outside of bankruptcy. The downgrade of NRG s credit ratings below investment grade in July 2002 has resulted in cash collateral requirements, as discussed previously and in Notes 4 and 7 to the audited consolidated financial statements. In addition, lower credit ratings would increase the relative cost of NRG s capital financing compared to historical levels, assuming NRG could obtain such financing.

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

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Credit Facilities and Other Sources of Liquidity As of October 31, 2003, we had the following credit facilities available to meet our liquidity needs:

Company	Facility	Drawn	Available	Cash	Liquidity	Maturity
			(Millions of dollars)			
NSP-Minnesota	$ 275	$ 40	$ 235	$119	$ 354	May 2004
NSP-Wisconsin	$ 0	$ 0	$ 0	$ 0	$ 0	
PSCo.	$ 350	$ 1	$ 349	$ 29	$ 378	May 2004
SPS	$ 100	$ 3	$ 97	$ 26	$ 123	Feb. 2004
Xcel Energy Holding Company	$ 400	$ 1	$ 399	$251	$ 650	Nov. 2005
Total	$1,125	$ 45	$1,080	$425	$1,505	

We expect to accumulate additional cash at the holding company level during 2003 from the lower federal income tax payments resulting from the expected tax benefit associated with our investment in NRG and from the receipt of operating company dividends. Restrictions by state regulatory commissions, debt agreements and PUHCA limit the amount of dividends our utility subsidiaries may pay to us.

On October 20, 2003, we completed the sale of Black Mountain Gas Company to Southwest Gas Corporation. Black Mountain Gas is a natural gas and propane distribution company serving approximately 8,500 natural gas customers and 2,500 propane customers in Arizona. Proceeds from the sale were $24 million.

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

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

Substantially all of NRG s operations are conducted by project subsidiaries and project affiliates. NRG s cash flow and ability to service corporate-level indebtedness when due is dependent upon receipt of cash dividends and distributions or other transfers from NRG s projects and other subsidiaries. NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its project s cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. In August 2002, NRG suspended substantially all of its acquisition and development activities indefinitely, pending a comprehensive restructuring of NRG. The debt agreements of NRG s subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As discussed elsewhere in this prospectus, NRG is in bankruptcy and therefore is in default under all of its debt obligations, including the following defaults as of September 30, 2003:

$350 million 8.25% Senior Unsecured Notes due 2010 issued by NRG;

Failure to make $14.4 million interest payment due on September 16, 2002;

Failure to make $14.4 million interest payment due on March 17, 2003; and

Failure to make $14.4 million interest payment due on September 16, 2003;

$250 million 8.70% Remarketable or Redeemable Securities due 2005 issued by NRG Energy Pass-Through Trust 2000-1;

Failure to make $10.9 million interest payment due on September 16, 2002;

Failure to make $10.9 million interest payment due on March 17, 2003; and

Failure to make $10.9 million interest payment due on September 15, 2003;

$240 million 8.0% Remarketable or Redeemable Securities due 2013 issued by NRG;

Failure to make $9.6 million interest payment due on November 1, 2002; and

Failure to make $9.6 million interest payment due on May 1, 2003;

$350 million 7.75% Senior Unsecured Notes due 2011 issued by NRG;

Failure to make $13.6 million interest payment due on October 1, 2002; and

Failure to make $13.6 million interest payment due on April 1, 2003;

$500 million of 8.625% Senior Unsecured Notes due 2031 issued by NRG;

Failure to make $21.6 million interest payment due on October 1, 2002; and

Failure to make $21.6 million interest payment due on April 1, 2003;

$300 million of 7.50% Senior Unsecured Notes due 2009 issued by NRG;

Failure to make $11.3 million interest payment due on December 1, 2002; and

Failure to make $11.3 million interest payment due on June 1, 2003;

$250 million of 7.50% Senior Unsecured Notes due 2007 issued by NRG;

Failure to make $9.4 million interest payment due on December 15, 2002; and

Failure to make $9.4 million interest payment due on June 15, 2003;

$340 million of 6.75% Senior Unsecured Notes due 2006 issued by NRG;

Failure to make $11.5 million interest payment due on January 15, 2003; and

Failure to make $11.5 million interest payment due on July 15, 2003;

$125 million of 7.625% Senior Unsecured Notes due 2006 issued by NRG;

Failure to make $4.8 million interest payment due on February 1, 2003; and

Failure to make $4.8 million interest payment due on August 1, 2003;

NRG Equity Units (NRZ) and related 6.50% Senior Unsecured Debentures due 2006 issued by NRG;

Failure to make $4.7 million interest payment due on November 16, 2002;

Failure to make $4.7 million interest payment due on February 17, 2003;

Failure to make $4.7 million interest payment due on May 16, 2003; and

Failure to make $4.7 million interest payment due on August 16, 2003;

$1.0 billion 364-Day Revolving Credit Agreement dated March 8, 2002, among NRG, ABN Amro Bank NV, as Administrative Agent and the other parties;

Failure to make $6.5 million interest payment due on September 30, 2002;

Failure to make $18.6 million interest payment due on December 31, 2002;

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Failure to make $17.8 million interest payment due on March 31, 2003;

Failure to make $18.0 million interest payment due on June 30, 2003;

Failure to make $18.9 million interest payment due on September 30, 2003;

Missed minimum interest coverage ratio of 1.75x;

Violated minimum net tangible worth of $1.5 billion; and

Notice of default issued on February 27, 2003, rendering the debt immediately due and payable;

$125 million Standby Letter of Credit Facility dated November 30, 1999, among NRG, Australia and New Zealand Banking Group Limited, as Administrative Agent, and the other parties thereto;

Missed minimum interest coverage ratio of 1.75x;

Violated minimum net tangible worth of $1.5 billion;

Cross default to $1.0 billion revolving line of credit agreement;

Availability reduced to the amount outstanding, which was $103 million as of June 30, 2003;

Failure to make $417,558 payment of letter of credit facility fees due July 31, 2003; and

Failure to make $218,000 interest payment on drawn amount due July 1, 2003;

$2.0 billion Credit Agreement, dated May 8, 2001, among NRG Finance Company I LLC, Credit Suisse First Boston, as Administrative Agents, and the other parties thereto;

Failure to make $46.9 million in combined interest payments as of March 31, 2003;

Failure to fund equity obligations for construction;

Failure to post collateral requirements due under equity support agreement; and

Acceleration of debt on November 6, 2002, rendering the debt immediately due and payable;

$325 million Series A floating rate Senior Secured Bonds due 2019 issued by NRG Peaker Finance Company LLC;

Failure to remove liens placed on one of the project company assets;

A cross default resulting from failure by NRG Energy to make payments of principal, interest and other amounts due on NRG Energy s debt for borrowed money in excess of $50 million in the aggregate;

Notice of default issued on October 22, 2002; and

Acceleration of debt on May 13, 2003, rendering the debt immediately due and payable;

$500 million of 8.962% Series A-1 Senior Secured Notes due 2016 issued by NRG South Central Generating LLC;

Failure to make $20.2 million interest and $12.8 million principal payment due on September 16, 2002;

Failure to make $12.8 million principal payment due on March 17, 2003;

Failure to fund debt service reserve account; and

Acceleration of debt on November 21, 2002, rendering the debt immediately due and payable;

$300 million 9.479% Series B-1 Senior Secured bonds due 2024 issued by NRG South Central Generating LLC;

Failure to make $14.2 million interest payment due on September 16, 2002;

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Failure to fund debt service reserve account; and

Acceleration of debt on November 21, 2002, rendering the debt immediately due and payable;

$320 million of 8.065% Series A Senior Secured Bonds due 2004 issued by NRG Northeast Generating LLC;

Failure to make $53.5 million principal payment on December 15, 2002;

Failure to fund debt service reserve account; and

Failure to make $17.5 million principal payment due June 15, 2003;

$130 million of 8.824% Series B Senior Secured Bonds due 2015 issued by NRG Northeast Generating LLC;

Failure to fund debt service reserve account;

$300 million of 9.29% Series C Senior Secured Bonds due 2024 issued by NRG Northeast Generating LLC;

Failure to fund debt service reserve account;

$580 million Loan Agreement dated June 25, 2001, as amended, among MidAtlantic Generating LLC, JP Morgan Chase Bank, as Administrative Agent, and the other parties thereto;

Failure to fund the debt service reserve account;

$554 million, Credit and Reimbursement Agreement dated November 12, 1999, as amended, among, LSP Kendall Energy LLC, Societe General, as Administrative Agent and the other parties thereto;

Liens placed against project assets;

$181 million Loan Agreement dated November 30, 2001, as amended, among McClain LLC and Westdeutsche Landesbank Girozentrale, as Administrative Agent;

Failure to fund the debt service reserve account; and

Failure to comply with revenue allocation procedures under Article 3 of the Energy Management Services Agreement.

In addition to the foregoing, there may be additional technical defaults with respect to these or other NRG debt instruments. Further, defaults on or acceleration of the foregoing debt instruments may result in cross-defaults on or cross-acceleration of these or other NRG debt instruments.

For additional information on NRG s defaults on short-term and long-term borrowing arrangements, see Note 7 to the audited consolidated financial statements.

See Note 9 to the interim consolidated financial statements for a discussion of dividend arrearages on our preferred stock.

Registration Statements Our Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of September 30, 2003, we had approximately 399 million shares of common stock outstanding. In addition, our Articles of Incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On September 30, 2003, we had approximately 1 million shares of preferred stock outstanding. Registered securities available for issuance are as follows:

In June 2003, we issued the original senior notes in a private placement to qualified institutional buyers. The original senior notes were not registered under the Securities Act. On October 9, 2003, pursuant to a registration rights agreement, we filed a registration statement on Form S-4 registering the exchange senior notes offered hereby.

In May 2003, we registered the resale of $230 million of 7.5 percent senior convertible notes with the SEC. The notes had been previously sold to qualified institutional buyers.

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In April 2003, PSCo filed a registration statement on Form S-3 with the SEC, effectively registering $800 million of new secured first collateral trust bonds or unsecured senior debt securities. PSCo has approximately $225 million remaining under this registration statement.

In March 2003, PSCo issued $250 million of 4.875 percent, first collateral trust bonds due 2013. The bonds were issued in a private placement to qualified institutional buyers and were not registered under the Securities Act. On June 11, 2003, pursuant to a registration rights agreement, PSCo filed a registration statement on Form S-4 for an exchange offer for those bonds.

In February 2002, we filed a $1 billion shelf registration with the SEC. We may issue debt securities, common stock and rights to purchase common stock under this shelf registration. We have approximately $482.5 million remaining under this registration statement.

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

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 statement.

Financing Activities We and our subsidiaries engaged in the following financing activities in 2003.

On October 6, 2003, SPS issued $100 million of unsecured senior notes due 2033. The debt was issued to refinance existing higher coupon securities as described below. The notes were sold to qualified institutional buyers in a private placement not registered under the Securities Act.

On October 15, 2003, NSP-Wisconsin redeemed $110 million of its 7.25 percent first mortgage bonds due 2023. The redemption price was 102.84 percent of the principal amount.

On October 15, 2003, SPS trust subsidiary Southwestern Public Service Capital I redeemed $100 million of 7.85 percent Trust Originated Preferred Securities. The redemption price for each security was $25 principal amount plus accrued distributions of $0.240 per preferred security.

On October 2, 2003, NSP-Wisconsin issued $150 million of 5.25 percent first mortgage bonds due 2018. The debt was issued to replace debt maturing in 2003 and to refinance other existing higher coupon debt as described below. The bonds were sold to qualified institutional buyers in a private placement not registered under the Securities Act.

On October 1, 2003, NSP-Minnesota redeemed $13.7 million of variable rate tax-exempt pollution control refund revenue bonds. The redemption price was 100 percent of the principal amount plus accrued interest.

On September 2, 2003, PSCo issued $300 million of 4.375 percent first collateral trust bonds due 2008 and $275 million of 5.50 percent first collateral trust bonds due 2014.

On August 8, 2003, NSP-Minnesota issued $200 million of 2.875 percent first mortgage bonds due 2006 and $175 million of 4.75 percent first mortgage bonds due 2010. The debt replaced debt that matured in March and April of 2003 and helped fund the redemption of $200 million of Trust Originated Preferred Securities on July 31, 2003, which was initially funded as described below.

On July 31, 2003, NSP-Minnesota redeemed $200 million of 7.875 percent Trust Originated Preferred Securities of NSP Financing I, its wholly owned subsidiary. The redemption price for each security was its $25 principal amount plus a $0.1695 unpaid distribution. NSP-Minnesota initially funded this redemption with cash on hand, availability under its credit facility and a short-term loan from the Xcel Energy holding company.

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PSCo engaged in the following redemptions:

On June 30, 2003, PSCo redeemed its $145 million of 8.75 percent first mortgage bonds due March 1, 2022. The redemption price was 100 percent of the principal amount plus a 3.76 percent call premium and accrued interest.

On June 30, 2003, PSCo s trust subsidiary PSCo Capital Trust I redeemed its $194 million of 7.60 percent Trust Originated Preferred Securities. The redemption price for each security was its $25 principal amount plus a $0.475 unpaid distribution.

The redemptions were temporarily funded from the $300 million short-term credit facility, the $350 million revolving credit facility, and cash on hand.

In June 2003, we issued $195 million of 3.40 percent senior notes due 2008. The notes were sold to qualified institutional buyers in a private placement not registered under the Securities Act.

In May 2003, we registered the resale of $230 million of 7.5 percent senior convertible notes due 2007 with the SEC. The notes had been previously sold to qualified institutional buyers in a private placement not registered under the Securities Act.

In March 2003, PSCo issued $250 million of 4.875 percent first collateral trust bonds due 2013. The bonds were sold to qualified institutional buyers in a private placement not registered under the Securities Act.

Short-term debt and financial instruments are discussed in Note 9 to the interim consolidated financial statements.

Financing Plans We currently plan no additional long-term debt issuances during the remainder of 2003.

Other Liquidity and Capital Resource Considerations

NRG Voluntary Bankruptcy Petition As discussed in Note 4 to the interim consolidated financial statements, since mid-2002, NRG has experienced severe financial difficulties, resulting primarily from lower prices for power and declining credit ratings. These financial difficulties have caused NRG to, among other things, fail to make payments of interest and/or principal aggregating over $400 million on outstanding indebtedness of over $4 billion and incur asset impairment charges and other costs in excess of $3 billion for the year ended December 31, 2002. These asset impairment charges include write-offs for anticipated losses on sales of several NRG projects as well as anticipated losses related to projects for which NRG has stopped funding.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us. We would pay up to $752 million to NRG to settle all claims of NRG against us, including all claims under a capital support agreement between us and NRG. The principal terms and contingencies to consummation of the settlement are discussed in Note 4 to our interim consolidated financial statements.

Commencing on May 14, 2003, NRG and certain of its affiliates, filed voluntary petitions for bankruptcy under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York to restructure their debt. The filing included NRG s plan of reorganization which incorporates the terms of an overall settlement (based on the tentative settlement discussed above) among us, NRG and various members of NRG s major credit constituencies that provides for payments by us to NRG and its creditors of up to $752 million.

We expect to finance the payments under the overall settlement with cash on hand at the holding company level and with funds from the tax benefits associated with our write-off of its investment in NRG. See the further discussion of the tax implications of the bankruptcy and settlement agreement in Notes 4 and 6 to the interim consolidated financial statements. Upon the effective date of the NRG plan of

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reorganization, our exposure on any guarantees or other credit support obligations incurred by us for the benefit of NRG or any subsidiary would be terminated or other arrangements would be made such that we have no further liability and any cash collateral posted by us would be returned to us. As of October 31, 2003, no cash collateral was posted.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities; to consolidate and pool the entities assets and liabilities; and to treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. In the event the settlement described above is not effectuated, we believe that any effort to substantively consolidate us with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims, or other claims under piercing the corporate veil, alter ego, control person or related theories, in the NRG bankruptcy proceeding. If a bankruptcy court were to allow substantive consolidation of us and NRG or if another court were to allow related claims, it would have a material adverse effect on us.

The accompanying interim consolidated financial statements and related notes do not necessarily reflect future conditions or matters that may arise as a result of NRG s bankruptcy filing and its ultimate resolution. Pending the outcome of its voluntary bankruptcy petition, NRG remains subject to substantial doubt as to its ability to continue as a going concern. See Note 5 to the interim consolidated financial statements for discussion of the change in our financial statement presentation of NRG in 2003 as a result of the bankruptcy filing. In addition, included in the interim consolidated financial statements is our pro forma income statement information for the nine months ended September 30, 2002, presenting NRG under the equity method, on a basis comparable to the year-to-date income statement for 2003 included herewith. Pro forma financial information has not been provided for the effects on us of actually divesting NRG once it emerges from bankruptcy due to the limited nature of such effects. In relation to the deconsolidated, equity method reporting of NRG in 2003 (and the corresponding pro forma amounts for periods prior to 2003), these divestiture effects would be limited to the payment of the settlement obligations (that is, elimination of the negative investment) and the discontinuance of recording any equity in NRG s losses.

We believe that the ultimate resolution of NRG s financial difficulties and going-concern uncertainty will not affect our ability to continue as a going concern. We are not dependent on cash flows from NRG. We believe that our cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund our non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, we believe we will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

During 2000, 2001 and 2002 and the first nine months of 2003, there were no disagreements with our independent public accountants on accounting principles or practices, financial statement disclosures, or auditing scope or procedures.

On March 27, 2002, the Audit Committee of our Board of Directors recommended, and our Board approved, the decision to engage Deloitte & Touche LLP, subject to completion of their customary acceptance procedures, as our new principal independent accountants for 2002. Accordingly, on March 27, 2002, our management informed Arthur Andersen LLP that the firm would no longer be engaged as our principal independent accountants. The reports of Arthur Andersen LLP on our financial statements for the year ended December 31, 2001 or 2000 did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles. Further, during 2000, 2001 and 2002 and the first nine months of 2003, there have been no reportable events (as defined in Commission Regulation S-K Item 304(a)(1)(v)).

Arthur Andersen LLP furnished us with a letter addressed to the SEC stating that it agreed with the above statements.

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BUSINESS

Company Overview

On August 18, 2000, NCE and NSP merged (the Merger) and formed Xcel Energy Inc., a Minnesota corporation. We are a registered holding company under PUHCA. As part of the Merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of ours named Northern States Power Company. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. As a stock-for-stock exchange for shareholders of both companies, the Merger was accounted for as a pooling-of-interests and accordingly, amounts reported for periods prior to the Merger have been restated for comparability with post-Merger results.

We directly own five utility subsidiaries that serve electric and natural gas customers in 11 states. These five utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Cheyenne. Their service territories include portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Our regulated businesses also include WGI, an interstate natural gas pipeline company. Prior to January 2003, our regulated businesses included Viking. On October 20, 2003, we completed the sale of BMG, which serves customers in portions of Arizona

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG. As a result of the exchange of Xcel Energy shares for publicly held shares of NRG, which was completed in June 2002, NRG is now an indirect wholly-owned subsidiary of ours. NRG is a global energy company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products. As discussed previously, on May 14, 2003, NRG and some of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

In addition to NRG, our nonregulated subsidiaries include:

- UE, which is involved in engineering, construction and design;
- Seren, which is involved in broadband telecommunications services;
- e prime, which is involved in natural gas marketing and trading;
- Planergy, which is involved in energy management consulting and demand-side management services;
- Eloigne, which is involved in the ownership of rental housing projects that qualify for low-income housing tax credits; and
- XEI, an international independent power producer.

We were incorporated under the laws of Minnesota in 1909. Our principal executive offices are located at 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota 55402 and our telephone number at that location is (612) 330-5500.

For information on our nonregulated subsidiaries, see Nonregulated Subsidiaries below. For information regarding our segments and foreign revenues, see Note 21 to the audited consolidated financial statements and Note 11 to the interim consolidated financial statements.

NSP-Minnesota

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. NSP-Minnesota provides generation, transmission and distribution of electricity in Minnesota, North Dakota and South Dakota. NSP-Minnesota also purchases, distributes and sells natural gas to retail customers and transports customer-owned gas in Minnesota, North Dakota and South Dakota. NSP-Minnesota provides retail electric utility service to approximately 1.3 million customers and gas utility service to approximately 430,000 customers.

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NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; and NSP Nuclear Corp., which holds NSP-Minnesota s interest in the Nuclear Management Co.

NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 230,000 retail customers in northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin is also engaged in the distribution and sale of natural gas in the same service territory to approximately 90,000 customers in Wisconsin and Michigan.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reserves; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is an operating utility engaged principally in the generation, purchase, transmission, distribution and sale of electricity and the purchase, transportation, distribution and sale of natural gas. PSCo serves approximately 1.3 million electric customers and approximately 1.2 million gas customers in Colorado.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc., which owns certain real estate interests of PSCo; PSR Investments, Inc., which owns and manages permanent life insurance policies on certain employees; and Green and Clear Lakes Co., which owns water rights. PSCo also holds controlling interests in several other relatively small ditch and water companies whose capital requirements are not significant.

SPS

SPS was incorporated in 1921 under the laws of New Mexico. SPS is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas. A major portion of SPS retail electric operating revenues is derived from operations in Texas.

Prior to October 15, 2003, SPS owned a direct subsidiary, SPS Capital I, which was a special purpose financing trust.

Other Regulated Subsidiaries

Cheyenne was incorporated in 1900 under the laws of Wyoming. Cheyenne is an operating utility engaged in the purchase, transmission, distribution and sale of electricity and natural gas primarily serving approximately 37,000 electric customers and 30,000 natural gas customers in and around Cheyenne, Wyoming.

BMG was incorporated in 1999 under the laws of Arizona. BMG is a natural gas and propane distribution company, located in Cave Creek, Arizona, with approximately 8,500 natural gas customers and 2,500 propane customers. On October 20, 2003, we completed the sale of BMG.

On January 17, 2003, we completed the sale of Viking, including its ownership interest in Guardian Pipeline, L.L.C., to a subsidiary of Northern Border Partners, L.P. During the time we owned Viking, it owned and operated an interstate natural gas pipeline serving portions of Minnesota, Wisconsin and North Dakota.

WGI was incorporated in 1990 under the laws of Colorado. WGI is a natural gas transmission company engaged in transporting natural gas from Chalk Bluffs, Colorado, to Cheyenne, Wyoming.

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Utility Regulation

Ratemaking Principles

Our system is subject to the jurisdiction of the SEC under PUHCA. The rules and regulations under PUHCA generally limit the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions. See additional discussion of PUHCA requirements under Management s Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Results of Operations and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

The FERC has jurisdiction over rates for electric transmission service and electric energy sold at wholesale in interstate commerce, hydro facility licensing and certain other activities of our utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of our other activities.

We are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. We strive to comply with all rules and regulations issued by the various agencies.

NSP-Minnesota

Retail rates, services and other aspects of NSP-Minnesota s operations are subject to the jurisdiction of the MPUC, the North Dakota Public Service Commission (NDPSC) and the South Dakota Public Utilities Commission (SDPUC) within their respective states. The MPUC also possesses regulatory authority over aspects of NSP-Minnesota s financial activities, including security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota s electric resource plans and gas supply plans for meeting customers future energy needs. The MPUC also certifies the need for generating plants greater than 50 megawatts and transmission lines greater than 100 kilovolts. NSP-Minnesota has received authorization from the FERC to act as a power marketer.

The Minnesota Environmental Quality Board (MEQB) is empowered to select and designate sites for new power plants with a capacity of 50 megawatts or more and wind energy conversion plants with a capacity of five megawatts or more. It also designates routes for electric transmission lines with a capacity of 100 kilovolts or more. No power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MEQB.

NSP-Wisconsin

NSP-Wisconsin is subject to regulation of similar scope by the Public Service Commission of Wisconsin (PSCW) and the Michigan Public Service Commission (MPSC). In addition, each of the state commissions certifies the need for new generating plants and electric and retail gas transmission lines of designated capacities to be located within the respective states before the facilities may be sited and built.

The PSCW has a biennial filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the two-year period beginning the following January. The filing procedure and review generally allow the PSCW sufficient time to issue an order effective with the start of the test year.

PSCo

PSCo is subject to the jurisdiction of the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is subject to the jurisdiction of the FERC with respect to its wholesale electric operations and accounting practices and policies. PSCo has received authorization from the FERC to act as a power marketer. Also, PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.

SPS

The PUCT has jurisdiction over SPS Texas operations as an electric utility and over its retail rates and services. The municipalities in which SPS operates in Texas have original jurisdiction over SPS rates in those communities. The New Mexico Public Regulatory Commission (NMPRC) has jurisdiction over the issuance of securities and accounting. The NMPRC, the Oklahoma Corporation Commission and the Kansas Corporation Commission have jurisdiction with respect to retail rates and services in their respective states. The FERC has jurisdiction over SPS rates for wholesale sales for resale and the transmission of electricity in interstate commerce. SPS has received authorization from the FERC to make wholesale electricity sales under market-based prices.

Cheyenne

Cheyenne is subject to the jurisdiction of the Wyoming Public Service Commission with respect to its facilities, votes, accounts, services and issuances of securities.

Other

WGI is subject to the FERC jurisdiction and holds a FERC certificate, which allows it to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act.

Fuel, Purchased Gas and Resource Adjustment Clauses

NSP-Minnesota

NSP-Minnesota s retail electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy. NSP-Minnesota is permitted to recover financial instrument costs through a fuel clause adjustment, a mechanism that allows NSP-Minnesota to bill customers for the cost of fuel used to generate electricity at its plants and energy purchased from other suppliers. Changes in capacity charges are not recovered through the fuel clause. NSP-Minnesota s electric wholesale customers do not have a fuel clause provision in their contracts. Instead, the contracts have an escalation factor.

Gas rate schedules for NSP-Minnesota include a purchased gas adjustment (PGA) clause that provides for rate adjustments for changes in the current unit cost of purchased gas compared with the last costs included in rates. The PGA factors in Minnesota are calculated for the current month based on the estimated purchased gas costs for that month. The MPUC has the authority to disallow certain costs if it finds the utility was not prudent in its procurement activities.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue and 0.5 percent of Minnesota gas revenue on conservation improvement programs (CIP). These costs are recovered through an annual recovery mechanism for electric and gas conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually.

NSP-Wisconsin

NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference outside a prescribed range, the PSCW may hold hearings limited to fuel costs and revise rates (upward or downward). Any revised rates would be effective until the next rate case. The adjustment approved is calculated on an annual basis, but applied prospectively. Most of NSP-Wisconsin s wholesale electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

NSP-Wisconsin has a gas cost recovery mechanism to recover the actual cost of natural gas.

NSP-Wisconsin s gas and retail electric rate schedules for Michigan customers include gas cost recovery factors and power supply cost recovery factors, which are based on 12-month projections. After each 12-month

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period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

PSCo

PSCo currently has six adjustment clauses that recover fuel, purchased energy and resource costs: the incentive cost adjustment (ICA), the interim adjustment clause (IAC), the air quality improvement rider (AQIR), the gas cost adjustment (GCA), the steam cost adjustment (SCA) and the demand side management cost adjustment (DSMCA). These adjustment clauses allow certain costs to be recovered from our retail customers. For certain adjustment mechanisms, PSCo is required to file applications with the CPUC for approval in advance of the proposed effective dates.

The ICA recovers a portion of PSCo s prudently-incurred fuel costs, purchased energy costs and purchased wheeling costs (collectively referred to as Energy Costs) through an incentive mechanism. The ICA recovers 50% of the Energy Costs over the benchmark $12.78/MWH of Energy Costs included in electric base rates; if the Energy Costs during a year average lower than the $12.78/MWH benchmark, then the ICA returns to customers 50% of the difference between the lower Energy Costs and the benchmark. The ICA applied to the PSCo from 1997 through 2002. Under a 2002 settlement agreement, PSCo s recovery of 2002 ICA Costs has been amortized over a 34 month period ending March 31, 2005.

The IAC recovers 100% of PSCo s prudently-incurred 2003 Energy Costs over the amount of Energy Costs included in electric base rates. During 2003, retail customers are paying both the amortized ICA and the IAC.

Beginning January 1, 2004 through December 31, 2006, the Company will recover its prudently-incurred Energy Costs that are above the level of Energy Costs in the electric base rates through a new clause called the Electric Commodity Adjustment or ECA . The ECA is an incentive mechanism that has been patterned generally after PSCo s ICA. The ECA compares PSCo s actual Energy Costs over an annual period to a benchmark Energy Cost that is derived from a formula that varies with natural gas prices. However, under the ECA, the cost sharing around the benchmark is limited, such that PSCo s maximum exposure to un-recovered costs and maximum incentive from cost reduction is capped at $11.25 million dollars. From January 1, 2004 through March 31, 2005, PSCo retail customers will pay both the ICA and the ECA.

The ICA, the IAC and the ECA all provide for a deferred account which compares on a monthly basis the revenues received under the adjustment mechanism with the recoverable costs under the adjustment mechanism. The deferred balances are factored into the annual resetting of the rates charged under these mechanisms.

The AQIR recovers over a fifteen year period the projected levelized incremental cost (including capital cost, operating and maintenance cost, fuel cost and purchased energy cost) incurred by PSCo as a result of voluntary investments in air quality improvement. The AQIR also has a deferred account which is used in the annual resetting of the AQIR rate.

PSCo, through its SCA, is allowed to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base rates. The SCA rate is revised annually to coincide with changes in fuel costs. Through its GCA, PSCo is allowed to recover its actual costs of purchased gas. The GCA rate is revised at least annually to coincide with changes in purchased gas costs. Purchased gas costs and revenues received to recover gas costs are compared on a monthly basis and differences are deferred. In 2002, PSCo requested to modify the GCA to allow for monthly changes in gas rates. A final decision on this proceeding is expected in 2003.

The DSMCA clause currently permits PSCo to recover DSM costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. PSCo also has implemented a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the DSMCA.

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SPS

Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS rates. If it appears that SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the PUCT. The rule requires refunding and surcharging under/over-recovery amounts, including interest, when they exceed 4 percent of the utility s annual fuel and purchased power costs, as allowed by the PUCT, if this condition is expected to continue. PUCT regulations require periodic examination of SPS fuel and purchased power costs, the efficiency of the use of such fuel and purchased power, fuel acquisition and management policies and purchase power commitments. Under the PUCT s regulations, SPS is required to file an application for the PUCT to retrospectively review at least every three years the operations of SPS electric generation and fuel management activities.

The NMPRC regulations provide for a fuel and purchased power cost adjustment clause for SPS New Mexico retail jurisdiction. SPS files monthly and annual reports of its fuel and purchased power costs with the NMPRC, which include the current over/under fuel collection calculation, plus interest. In January 2002, the NMPRC authorized SPS to implement a monthly adjustment factor on an interim basis beginning with the February 2002 billing cycle.

Cheyenne

All electric demand and purchased power costs are recoverable through an energy adjustment clause. Differences in costs incurred from costs recovered in rates are deferred and recovered through prospective adjustments to rates. However, rate changes for cost recovery require WPSC approval before going into effect. Historically, customers have been provided carrying costs on overcollected costs, but Cheyenne has not been allowed to collect carrying charges for under recovered costs.

Other Regulatory Mechanisms and Requirements

NSP-Minnesota

In December 2000, the NDPSC approved our PLUS performance-based regulation proposal for its electric operations in the state. The plan established operating and service performance standards in the areas of system reliability, customer satisfaction, price and worker safety. NSP-Minnesota s performance determines the range of allowed return on equity for its North Dakota electric operations. The plan will generate refunds or surcharges when earnings fall outside of the allowed return on equity range. The PLUS plan will remain in effect through 2005.

PSCo

The CPUC established an electric performance-based regulatory plan (PBRP) under which PSCo operates. See further discussion above under Management s Discussion and Analysis of Financial Condition and Results of Operation.

SPS

Prior to June 2001, SPS operated under an earnings test in Texas, which required excess earnings to be returned to the customers. In May 2000, SPS filed its 1999 earnings report with the PUCT, indicating no excess earnings. In September 2000, the PUCT staff and the Office of Public Utility Counsel filed with the PUCT a notice of disagreement, indicating adjustments to SPS calculations, which would result in excess earnings. During 2000, SPS recorded an estimated obligation of approximately $11.4 million for 1999 and 2000. In February 2001, the PUCT ruled on the disputed issues in the 1999 report and found that SPS had excess earnings of $11.7 million. This decision was appealed by SPS to the District Court. On December 11, 2001, SPS entered into an overall settlement of all earnings issues for 1999 through 2001, which reduced the excess earnings for 1999 to $7.3 million and found that there were no excess earnings for 2000 or through June 2001. The settlement also provided that the remaining excess earnings for 1999 could be used to offset

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approved transition costs that SPS was seeking to recover. The PUCT approved the overall settlement on January 10, 2002.

Pending Regulatory Matters

Xcel Energy

PUHCA Financing Authority We are a public utility holding company registered with the SEC under PUHCA. PUHCA contains limitations on the ability of registered holding companies and certain of their subsidiaries to issue securities. Such registered holding companies and subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC.

Because the exemptions available to us are limited, we sought and received financing authority from the SEC under PUHCA for various financing arrangements. Our original financing authority permitted us, subject to satisfaction of certain conditions, to issue through September 30, 2003 up to $2 billion of common stock and long-term debt and $1.5 billion of short-term debt at the holding company level. We have issued $2 billion of long-term debt and common stock. Other than the $130 million under our 5-year facility and any current maturities of long-term debt, we have no short-term debt outstanding at the holding company level. On September 30, 2003, the SEC approved our request for an extension of our financing authority through June 30, 2005 and to increase our authority to issue common stock and long-term debt from $2 billion to $2.5 billion. The SEC approval is discussed in detail above under Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Sources.

On December 20, 2002, we filed a request with the SEC seeking, among other things, authorization to pay up to $260 million of dividends out of capital and unearned surplus in the event we cease to have retained earnings. The amount of dividends that we can pay is limited by PUHCA, in that we may not pay dividends out of capital or unearned surplus without approval of the SEC. On May 29, 2003, we received approval to pay up to $152 million of dividends out of capital and unearned surplus, but the SEC reserved jurisdiction over the remainder of our request.

As a result of additional write-downs at NRG, our retained earnings were a deficit of approximately $245 million on June 30, 2003. On September 12, 2003, we requested that the SEC release jurisdiction over the payment of common and preferred dividends out of capital and unearned surplus for the third quarter of 2003. No such authorization has yet been received. On September 25, 2003, we announced that our normal third quarter dividend would be delayed.

On September 30, 2003, our retained earnings were approximately $43 million. On October 22, 2003, we declared third quarter dividends on our preferred stock, based on the third quarter results, which indicated sufficient retained earnings were available to do so. The dividends were paid on November 10, 2003, to preferred stock shareholders of record on October 31, 2003. Assuming that the NRG plan of reorganization is approved by NRG s creditors in December 2003 as expected and earnings for 2003 are as anticipated, we currently expect to have retained earnings sufficiently positive before the end of 2003 to pay the third quarter common stock dividend in December as well as declare the fourth quarter common and preferred dividends (normally payable in January 2004).

FERC and PUHCA Approvals Related to NRG On July 22, 2003, we and NRG submitted a joint application to the FERC requesting approval for us to dispose of our interest in NRG by implementing the proposed plan of reorganization filed in the NRG bankruptcy proceeding. On October 8, 2003, the FERC issued an order approving the application.

On July 28, 2003, we and NRG submitted an application to SEC under the PUHCA seeking authorization under the Act to perform those acts and consummate those transactions contemplated as part of NRG s proposed plan of reorganization. On October 10, 2003, the SEC issued an order approving the application.

Investigations into Trading Practices On May 8, 2002, in response to disclosure by Enron Corporation of certain trading strategies used in 2000 and 2001 that may have violated market rules, the FERC ordered all

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sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including us, PSCo and NRG, to respond to data requests, including requests about the use of certain trading strategies. On May 22, 2002, we reported to the FERC that we had not engaged directly in the trading strategies identified in the May 8th inquiry.

However, we reported that at times during 2000 and 2001, our regulated operations did sell energy to another energy company that may then have resold the electricity for delivery into California as part of an overstated electricity load in schedules submitted to the California Independent System Operator. During that period, our regulated operations made sales to the other electricity provider of approximately 8,000 megawatt-hours in the California intra-day market, which resulted in revenues to us of approximately $1.5 million. We cannot determine from our records what part of such sales was associated with over-schedules due to the volume of records and the relatively small amount of sales.

On May 21, 2002, the FERC supplemented the May 8th request by ordering all sellers off wholesale electricity and/or ancillary services in the United States portion of the Western Systems Coordinating Council during 2000 and 2001 to report whether they had engaged in activities referred to as wash, round trip or sell/ buyback trading. On May 31, 2002, we reported to the FERC that we had not engaged in so-called round trip electricity trading as identified in the May 21st inquiry.

On May 13, 2002, independently and not in direct response to any regulatory inquiry, we reported that PSCo had engaged in transactions in 1999 and 2000 with the trading arm of Reliant Resources, Inc. (Reliant) in which PSCo bought power from Reliant and simultaneously sold the same quantity back to Reliant. For doing this, PSCo normally received a small profit. PSCo made a total pretax profit of approximately $110,000 on these transactions. These transactions included one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. In this transaction, PSCo agreed to buy from Reliant 15,000 megawatts per hour, during the off-peak hours of the months of November and December 1999. Collectively, these sales with Reliant consisted of approximately 10 million megawatt hours in 1999 and 1.8 million megawatt hours in 2000 and represented approximately 55 percent of our trading volumes for 1999 and approximately 15 percent of our trading volumes for 2000. The purpose of the non-profit transaction was in expectation of entering into additional future for-profit transactions, such as the ones described above. PSCo engaged in these transactions with Reliant for the proper commercial objective of making a profit. PSCo did not enter into these transactions to inflate volumes or revenues and, at the time the transactions occurred, the transactions were reported net in PSCo s financial statements.

On March 26, 2003, the FERC at its open meeting discussed this investigation and stated its intent to issue show cause orders to thirty identified market participants, requesting that these entities explain why their conduct did not constitute impermissible gaming under applicable tariffs and why they should not have to disgorge unjust profits or be subjected to other remedies. PSCo was not identified as one of these market participants. However, it was indicated that NRG would be asked to show cause why its prices from May to October, 2000, did not constitute economic withholding and inflated bidding and why it should not be required to disgorge unjust profits or be subjected to other remedies.

On June 25, 2003, the FERC issued a series of orders addressing the California electricity markets. Two of these were show cause orders. In the first show cause order, the FERC found that twenty-four entities may have worked in concert through partnerships, alliances or other arrangements to engage in activities that constitute gaming and/or anomalous market behavior. The FERC initiated the proceedings against these twenty-four entities requiring that they show cause why their behavior did not constitute gaming and/or anomalous market behavior. PSCo was not named in this order. In a second show cause order, the FERC indicated that various California parties, including the California Independent System Operator (CAISO), have alleged that forty-three entities individually engaged in one or more of seven specific types of practices that the FERC has identified as constituting gaming or anomalous market behavior within the meaning of the CAISO and California Power Exchange tariffs. PSCo was listed in an attachment to that show cause order as having been alleged to have engaged in one of the seven identified practices, namely circular scheduling. Subsequent to the show cause order, PSCo provided information to the FERC Trial Staff showing PSCo did not engage in circular scheduling. On August 29, 2003, the FERC Trial Staff filed a motion to dismiss PSCo

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from the show cause proceeding. Various California parties have opposed the motion to dismiss. They have also requested rehearing of the FERC s show cause orders contending that the FERC should have named PSCo in the show cause orders as an entity that had engaged in (i) a load shift transaction and (ii) a partnership that constituted gaming. PSCo has answered both the request for rehearing and the California parties opposition to FERC Trial Staff s motion to dismiss.

As discussed later, we and PSCo have received subpoenas from the Commodities Future Trading Commission for disclosure related to these round trip trades and other trading in electricity and natural gas for the period from January 1, 1999 to the present involving us or any of our subsidiaries.

We also have received a subpoena from the SEC for documents concerning round trip trades in electricity and natural gas with Reliant for the period from January 1, 1999 to the present. The SEC subpoena is issued pursuant to a formal order of private investigation that does not name us as a subject of the investigation. Based upon accounts in the public press, we believe that similar subpoenas in the same investigation have been served on other industry participants. We are cooperating with the regulators and taking steps to assure satisfactory compliance with the subpoenas.

Section 206 Investigation Against All Wholesale Electric Sellers In November 2001, the FERC issued an order under Section 206 of the Federal Power Act initiating a generic investigation proceeding against all jurisdictional electric suppliers making sales in interstate commerce at market-based rates. NSP-Minnesota, PSCo, SPS and certain NRG affiliates previously received FERC authorization to make wholesale sales at market-based rates, and have been engaged in such sales subject to rates on file at the FERC. The order proposed that all wholesale electric sales at market-based rates conducted starting 60 days after publication of the FERC order in the Federal Register would be subject to refund conditioned on factors determined by the FERC.

In December 2001, the FERC issued a supplemental order delaying the effective date of the subject to refund condition, but subject to further investigation and proceedings. Numerous parties filed comments in January 2002, and reply comments were filed in February of that year. Further, the FERC staff convened a conference in this proceeding in February 2002. The FERC has not yet acted on the matter.

California Market Manipulation The FERC has an ongoing investigation of potential manipulation of electric and natural gas prices, which involves hundreds of parties (including NRG s affiliate, West Coast Power) and substantial discovery. In June, 2001, the FERC initiated proceedings related to California s demand for $8.9 billion in refunds from power sellers who allegedly inflated wholesale prices during the energy crisis. Hearings have been conducted before an administrative law judge who issued an opinion in late 2002. The administrative law judge stated that after assessing a refund of $1.8 billion for unjust and unreasonable power prices between October 2, 2000 and June 20, 2001, power suppliers were owed $1.2 billion because the State of California was holding funds owed to suppliers.

In August 2002, the United States Court of Appeals for the Ninth Circuit granted a request by the Electricity Oversight Board, the California Public Utilities Commission, and others, to seek out and introduce to the FERC additional evidence of market manipulation by wholesale sellers. This decision resulted in the FERC ordering an additional 100 days of discovery in the refund proceeding, and also allowing the relevant time period for potential refund liability to extend back an additional nine months, to January 1, 2000.

On December 12, 2002, the FERC Administrative Law Judge Birchman issued a certification of proposed findings on California refund liability in docket number EL00-95-045 et al., which determined the method for calculating the mitigated energy market clearing price during each hour of the refund period. On March 26, 2003, the FERC issued an order on proposed findings on refund liability in docket number EL00-95-045 (Refund Order), adopting, in part, and modifying, in part, the proposed findings issued by Judge Birchman on December 12, 2002. In the refund order, the FERC adopted the refund methodology in the staff final report on price manipulation in western markets issued contemporaneously with the refund order in docket number PA02-2-000. This refund calculation methodology makes certain changes to Judge Birchman s methodology, because of the FERC staff s findings of manipulation in gas index prices. This could materially increase the estimated refund liability. The refund order directed generators wanting to recover any fuel costs

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above the mitigated market clearing price during the refund period to submit cost information justifying such recovery within 40 days of the issuance of the refund order. West Coast Power has submitted such cost information. The FERC announced in the refund order that it expects that refunds will be paid by suppliers by the end of summer 2003. The FERC, however, also maintained its previous rulings that it could not order refunds in docket number EL00-95-045 prior to the previously set refund effective date, October 2, 2000, contrary to the arguments of the California parties. The matter is still pending.

Commodity Futures Trading Commission Investigation On June 17, 2002, the Commodity Futures Trading Commission (CFTC) issued broad subpoenas to us on behalf of our affiliates, including PSCo and NRG, calling for production, among other things, of all documents related to natural gas and electricity trading (the June 2002 subpoenas). Since that time, we have produced documents and other materials in response to numerous more specific requests under the June 2002 subpoenas. Certain of these requests and our responses have concerned so-called round-trip trades. By a subpoena dated January 29, 2003, and related letter requests (the January 2003 subpoena), the CFTC has requested that we produce all documents related to all data submittals and documents provided to energy industry publications. Also beginning on January 29, 2003, the CFTC has sought testimony from 20 current and former employees and executives, and may seek additional testimony from other employees, concerning the reporting of energy transactions to industry publications. We have produced documents and other materials in response to the January 2003 subpoena, including documents identifying instances where e prime reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions.

In June 2003, as a result of our ongoing investigation of this matter, our representatives met with representatives of the CFTC and the Office of the United States Attorney for the District of Colorado. We have determined that e prime employees reported inaccurate trading information to one industry publication and may have reported inaccurate trading information to other industry publications. e prime ceased reporting to publications in 2002.

A number of energy companies have stated in documents filed with the FERC that employees reported fictitious natural gas transactions to industry publications. Several companies have agreed to pay between $3 million and $28 million to the CFTC to settle alleged violations related to the reporting of fictitious transactions. The CFTC has also brought a civil complaint against an energy company alleging false reporting and attempted market manipulation. In the complaint the CFTC requests damages as well as an order directing the energy company to disgorge benefits received from the alleged illegal acts. These and other energy companies are also subject to a recent order by the FERC placing requirements on natural gas marketers related to reporting, as well as a FERC policy statement regarding reporting of price indices. In addition, two individual traders from the companies that have been fined have been charged in criminal indictments with reporting fictitious transactions.

We continue to investigate this matter, and we and e prime have suspended and/or terminated several employees in connection with the reporting of inaccurate natural gas transactions to industry publications. Nevertheless, we believe that none of e prime s reporting to industry publications had any effect on the financial accounting treatment of any transaction recorded in our books and records. However, we are unable to determine if any reporting of inaccurate trade information to industry publications affected price indices. We are cooperating in the CFTC investigation, but cannot predict the outcome of any investigation.

FERC Transmission Inquiry The FERC has begun a formal, non-public inquiry relating to the treatment by public utility companies of affiliates in generator interconnection and other transmission matters. In connection with the inquiry, the FERC has asked us and our subsidiaries for certain information and documents. We and our subsidiaries are complying with the request.

PUHCA Regulation See the discussion of pending issues under PUHCA regulation under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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NSP-Minnesota

Minnesota Service Quality Investigation On August 8, 2002, the MPUC asked for information related to the impact of NRG s financial circumstances on NSP-Minnesota. Subsequent to that date, several local Minnesota newspaper articles alleged concerns about the reporting of service quality data and NSP-Minnesota s overall maintenance practices. In an order dated October 22, 2002, the MPUC directed the Minnesota Department of Commerce and the Office of the Attorney General Residential Utilities Division (the state agencies) to investigate the accuracy of NSP-Minnesota s reliability records and to allow for further review of its maintenance and other service quality measures. In addition, the order requires NSP-Minnesota to report specified financial information and work with interested parties on various issues to ensure NSP-Minnesota s commitments are fulfilled. The October 22, 2002 order references NSP-Minnesota s commitment (made at the time of the Merger) to not seek a rate increase until 2006 unless certain exceptions are met. In addition, among other requirements, the order imposes restrictions on NSP-Minnesota s ability to encumber utility property, provide intercompany loans and the method by which NSP-Minnesota can calculate its cost of capital in present and future filings before the MPUC. On January 3, 2003, the MPUC subsequently issued an order bifurcating the financial aspect of this proceeding from the state agency s inquiry into the NSP-Minnesota s service quality reporting and allowing the agencies to continue to investigate other allegations in existing dockets. As a result, the two matters proceeded under separate dockets. On March 10, 2003, the state agencies submitted a progress report to the MPUC drafted by the state agencies auditor, Fraudwise, an investigation firm. The report documented alleged instances of record keeping inconsistencies and misstatements in the record keeping system. NSP-Minnesota has publicly acknowledged that its record keeping system has deficiencies. In submitting the progress report, the state agencies noted, however, that the total outage duration stated would need to increase by nearly 33 million minutes to violate state-imposed standards.

On August 4, 2003, the state agencies jointly filed with the MPUC a report issued by Fraudwise. The findings of the August 4, 2003 report are generally consistent with the previously disclosed findings in Fraudwise s preliminary report that NSP-Minnesota s record keeping contains inconsistencies and misstatements and that it would be nearly impossible to establish the magnitude of misstatements in the record keeping system. The report also stated that NSP-Minnesota s records were unreliable and appear to have been manipulated to ensure compliance with state-imposed standards. On September 24, 2003, NSP-Minnesota and the state agencies announced that they had reached a settlement agreement. The agreement was submitted to the MPUC for approval. Among the settlement agreement s key provisions were:

- $1 million in refunds to Minnesota customers who have experienced the longest duration of outages, which have been accrued at September 30, 2003.

- Additional actions to improve system reliability in an effort to reduce outage frequency and duration. These actions will target the primary outage causes, including tree trimming and cable replacement. At least an additional $15 million, above amounts being currently recovered in rates, is to be spent in Minnesota on these outage prevention improvements by January 1, 2005.

- Development of a revised service quality plan containing a standard for service outage documentation, new performance measures, new thresholds for current performance measures and a new structure for consequences that will result from failure to meet these performance measures.

NSP-Minnesota is currently negotiating the details of the revised service quality plan with the state agencies. The new service quality plan, or a report on the progress of the negotiations, is expected to be filed with the MPUC on November 14, 2003.

South Dakota Service Quality Investigation In 2002, the South Dakota Public Utilities Commission (SDPUC) investigated our service quality. In particular, the investigation focused on NSP-Minnesota operations in the Sioux Falls area. NSP-Minnesota committed to a number of actions to improve reliability, which are being implemented, and to provide an updated 10-year capacity plan to the SDPUC by the end of 2003. NSP-Minnesota is working to complete the commitments made in December 2002 relating to service

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quality in the Sioux Falls area. NSP-Minnesota also is working with the SDPUC to provide information and to answer inquiries regarding service quality. No docket has been opened.

Minnesota Emissions Reduction Program On July 26, 2002, NSP-Minnesota filed for approval by the MPUC a proposal to invest in existing NSP-Minnesota generation facilities (AS King, High Bridge and Riverside) to reduce emissions under the terms of legislation adopted by the 2001 Minnesota Legislature. The proposal includes the installation of state-of-the-area pollution control equipment as the AS King plant and conversion to natural gas at the High Bridge and Riverside plants. Under the terms of the statute, the filing concurrently seeks approval of a rate recovery mechanism for the costs of the proposal, estimated to be a total of $1.1 billion with major expenditures anticipated to begin in 2005 and continuing through 2009. The rate recovery would be through an annual automatic adjustment mechanism authorized by 2001 legislation, outside a general rate case, and is proposed to be effective at the expiration of the NSP-Minnesota merger rate freeze, which extends through 2005 unless certain exemptions are triggered. The rate recovery proposed by NSP-Minnesota would allow recovery of financing costs of capital expenditures prior to the in-service date of each plant. The proposal is pending comments by interested parties. Other regulatory approvals, such as environmental permitting, are needed before the proposal can be implemented. On December 30, 2002, the Minnesota Pollution Control Agency issued a report to the MPUC in which it found that the NSP-Minnesota emission reduction proposal is appropriate and complies with the requirement of the 2001 legislation. The MPUC must now act on the proposal.

Renewable Cost Recovery Tariff In April 2002, NSP-Minnesota also filed for MPUC authorization to recover in retail rates the costs of electric transmission facilities constructed to provide transmission service for renewable energy. The rate recovery would be through an automatic adjustment mechanism authorized by 2001 legislation, outside a general rate case. In January 2003, the MPUC issued an order approving the tariff subject to certain modifications.

Electric Transmission Construction In December 2001, NSP-Minnesota filed for certificates of need authorizing construction of various high voltage transmission facilities to provide generator outlet for up to 825 megawatts of wind generation. The projected cost is approximately $160 million. On January 30, 2003, the MPUC voted to issue certificates of need supporting NSP-Minnesota s preferred transmission construction plan. The certificates of need were issued with conditions that require NSP-Minnesota to purchase wind powered electric generating capacity to match the increased transmission capacity created by the certified lines.

Filings will be made with the Minnesota Environmental Quality Board (MEQB) to decide routing issues associated with the transmission plan. MEQB decisions are expected by the end of 2003 and early 2004. Construction is expected to be complete in the spring of 2007.

Time-of-Use Pilot Project As required by MPUC orders, NSP-Minnesota was working to develop a time-of-use pilot project that would attempt to measure customer response and conservation potential of such a program. This pilot project explored providing customers with pricing signals and information that could better inform customer choices about their use of electricity based on its costs. NSP-Minnesota petitioned the MPUC for recovery of program costs. In an order dated July 2, 2003, the MPUC declined approval of the proposed pilot program. However, the order did provide directions that NSP-Minnesota could follow in requesting deferred accounting to allow for recovery of costs expended in this effort. Pursuant to that order, NSP-Minnesota filed a petition on September 11, 2003 for deferred accounting of approximately $2 million. The Department of Commerce has supported deferred accounting to provide for recovery of prudent, otherwise unrecovered and appropriate costs, subject to a normal prudence review process. The Office of the Attorney General has argued that cost recovery should be denied for several reasons. An MPUC hearing on these issues is expected in the first quarter of 2004.

Merger Agreement As part of the NCE and NSP merger approval process in Minnesota, NSP-Minnesota agreed to:

Reduce its Minnesota electric rates by $10 million annually through 2005;

Not increase its electric rates through 2005, except under limited circumstances;

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Not seek recovery of certain merger costs from customers; and

Meet various quality standards.

Midwest Independent Transmission System Operator, Inc. (MISO) Electric Market Initiative On July 25, 2003, MISO filed proposed changes to its regional open access transmission tariff to implement a new Transmission and Energy Markets Tariff (TEMT) that would establish certain wholesale energy and transmission service rates based on locational marginal cost pricing (LMP) to be effective in 2004. NSP-Minnesota and NSP-Wisconsin presently receive transmission services from MISO for service to their retail loads and would be subject to the new tariff, if approved by the FERC. After numerous parties, including several states, filed protests to the proposal, MISO filed on October 17, 2003 to withdraw the TEMT without prejudice to refiling. The FERC issued an order approving the withdrawal and provided guidance on MISO s proposals on October 29, 2003. MISO is now starting the stakeholder consultation process to prepare and submit a revised TEMT in 2004. Management believes any new tariff, if approved by the FERC, could have a material effect on wholesale power supply or transmission service costs to NSP-Minnesota and NSP-Wisconsin.

NSP-Wisconsin

2003 General Rate Case On June 1, 2003, NSP-Wisconsin filed its required biennial rate application with the PSCW requesting no change in Wisconsin retail electric and natural gas base rates. NSP-Wisconsin requested the PSCW approve its application without hearing, pending completion of the Staff s audit. An order is expected in late 2003 or early 2004.

Retail Electric Fuel Rates In August 2002, NSP-Wisconsin filed an application with the PSCW requesting a decrease in Wisconsin retail electric rates for fuel costs. The amount of the proposed rate decrease is approximately $6.3 million on an annual basis. The reasons for the decrease include moderate weather, lower than forecast market power costs and optimal plant availability. On August 7, 2002, the PSCW issued an order approving the fuel rate credit. The rate credit was effective on August 12, 2002.

On October 9, 2002, NSP-Wisconsin filed an application with the PSCW requesting another decrease in Wisconsin retail electric rates for fuel costs. The incremental amount of the second proposed rate decrease was approximately $5 million on an annual basis. The reasons for the additional decrease include continued moderate weather, lower than forecast market power costs, and optimal plant availability. On October 16, 2002, the PSCW issued an order approving the revised fuel rate credit, effective October 19, 2002.

On October 22, 2002, NSP-Wisconsin filed an application with the PSCW requesting the establishment of a new fuel monitoring range and fuel recovery factor for 2003. On January 30, 2003, the PSCW issued an order authorizing a new fuel monitoring range for 2003 and a new fuel recovery factor effective February 3, 2003. This results in an annual revenue increase of approximately $5 million from the fuel credit factor the PSCW approved October 16, 2002.

Michigan Transfer Pricing On October 3, 2002, the Michigan Public Service Commission denied NSP-Wisconsin s request for a waiver of the section of the Michigan Electric Code of Conduct (the Michigan Code) dealing with transfer pricing policy. The Michigan Code requires the price of goods and services provided by an affiliate to NSP-Wisconsin be at the lower of market price or cost plus 10 percent, and the price of goods and services provided by NSP-Wisconsin to an affiliate be at the higher of cost or market price. NSP-Wisconsin requested the waiver based on its belief that the Michigan Code conflicts with SEC requirements to price goods and services provided between affiliates at cost. In November 2002, NSP-Wisconsin filed a request for reconsideration of the October 3, 2002 order. During its January 31, 2003 meeting, the Michigan Public Service Commission considered NSP-Wisconsin s rehearing request and granted the Company s request for waiver from this section of the Michigan Code. In its decision, the Michigan Public Service Commission indicated that it should grant the waiver to avoid placing NSP-Wisconsin in a position where it may be unable to comply with the Michigan Code and the pricing standards enforced by the SEC.

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Midwest Independent Transmission System Operator, Inc. Electric Market Initiative As discussed above, on July 25, 2003, MISO filed proposed changes to its regional open access transmission tariff to implement a new Transmission and Energy Markets Tariff (TEMT) that would establish certain wholesale energy and transmission service rates based on locational marginal cost pricing (LMP) to be effective in 2004. NSP-Minnesota and NSP-Wisconsin presently receive transmission services from MISO for service to their retail loads and would be subject to the new tariff, if approved by the FERC. After numerous parties, including several states, filed protests to the proposal, MISO filed on October 17, 2003 to withdraw the TEMT without prejudice to refiling. The FERC issued an order approving the withdrawal and provided guidance on MISO s proposals on October 29, 2003. MISO is now starting the stakeholder consultation process to prepare and submit a revised TEMT in 2004. Management believes any new tariff, if approved by the FERC, could have a material effect on wholesale power supply or transmission service costs to NSP-Minnesota and NSP-Wisconsin.

PSCo

Merger Agreements Under the Stipulation and Agreement approved by the CPUC in connection with the Merger, PSCo agreed to:

file a combined electric, gas and steam rate case in 2002 with new rates effective in January 2003;

extend its ICA mechanism for one more year through December 31, 2002 with an increase in the ICA base rate from $12.78 per megawatt hour to a rate based on the 2001 actual costs;

continue the electric Performance Based Regulatory Plan and the electric Quality Service Plan through 2006 with an electric department earnings cap of 10.5 percent return on equity for 2002 and no earnings sharing for 2003;

develop a gas Quality of Service Plan for calendar year 2002 through 2007 performance;

reduce electric rates annually by $11 million for the period August 2000 to July 2002; and

cap merger costs associated with electric operations at $30 million and amortize such costs through 2002.

2002 General Rate Case In May 2002, PSCo filed a combined general retail electric, natural gas and thermal energy base rate case with the CPUC to address increased costs for providing energy to Colorado customers.

On April 4, 2003, a comprehensive settlement agreement between PSCo and all but one of the intervenors was executed and filed with the CPUC, which addressed all significant issues in the rate case. In summary, the settlement agreement, among other things, provides for:

annual base rate decreases 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 recovers 100 percent of prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates during 2003. This clause is projected to recover energy costs totaling approximately $216 million in 2003;

a new electric commodity adjustment clause (ECA) for 2004-2006, 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.

In June 2003, the CPUC issued its initial written order approving the settlement agreement. The new rates were effective July 1, 2003. The CPUC issued its final decision in the rate case on August 8, 2003. PSCo expects to file the rate design portion of the case on or before December 8, 2003.

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Gas Cost Prudence Review In May 2002, the staff of the CPUC filed testimony in PSCo s gas cost prudence review case, recommending $6.1 million in disallowances of gas costs for the July 2000 through June 2001 gas purchase year. Hearings were held before an administrative law judge in July 2002. On February 10, 2003, the judge issued a recommended decision rejecting the proposed disallowances and approving PSCo s gas costs for the subject gas purchase year as prudently incurred. On June 6, 2003, the CPUC issued its order denying exceptions to the administrative law judge s recommended decision. The CPUC upheld the finding that PSG was prudent and reasonable in its handling of the Western Natural Gas default in January 2001.

Annual Gas Cost Adjustment Filing PSCo recovers the cost of natural gas that it purchases for its customers use through a gas cost adjustment mechanism in its gas rates filed with the CPUC. On September 16, 2003, PSCo requested an $88.8 million increase in prices for its customers through its annual gas cost adjustment filing to reflect higher current and forecasted costs of natural gas. The price increase was approved by the CPUC and went into effect on October 1, 2003.

Capacity Cost Adjustment In October 2003, PSCo filed with the CPUC an application to recover approximately $31.5 million of incremental capacity costs through a purchased capacity cost adjustment (PCCA) rider beginning March 1, 2004. The purpose of the PCCA is to recover purchased capacity payments to third party power suppliers that will not be recovered in PSCo s current base electric rates or other recovery mechanism. In addition, PSCo has proposed to return to its retail customers 100 percent of any electric earnings in excess of its authorized rate of return on equity allowed in the last rate case, currently 10.75 percent. A decision by the CPUC is expected in 2004.

Gas Rate Reduction In September 2002, PSCo filed a request with the CPUC for a $65 million reduction in the natural gas cost component of our rates in Colorado. The gas cost adjustment would reduce overall customer bills starting October 1, 2002. The CPUC approved the requested decrease by order issued September 27, 2002.

Gas Rate Adjustment In March 2003, PSCo filed a request with the CPUC for a $95.6 million gas cost adjustment increase through September 2003, to reflect an increase in current and forecasted costs for natural gas. The CPUC approved the requested increase by order issued March 20, 2003. The cost adjustment will not result in any additional gas margin for PSCo, as the increase reflects additional costs for purchasing natural gas on behalf of its customers. Natural gas costs are passed on to customers on a dollar-per-dollar basis.

Fuel Adjustment Clause Proceeding Certain of PSCo s wholesale power customers filed complaints with the FERC in 2002 alleging that PSCo had been improperly collecting certain fuel and purchased energy costs through the wholesale fuel cost adjustment clause included in their rates. The FERC consolidated these complaints and set them for hearing. The complainants filed initial testimony in late April 2003 claiming the improper inclusion of fuel and purchased energy costs in the range of $40 million to $50 million related to the periods 1996 through 2002. PSCo submitted answering testimony in June 2003. In rebuttal testimony the complainants filed on August 1, 2003, they quantified their claims at approximately $30 million. During the week of August 18, 2003, PSCo reached agreements in principle with all of the complainants under which such claims, as well as issues those customers had raised in response to PSCo s wholesale general rate case filing discussed elsewhere in this prospectus, were compromised and settled. Under the settlement agreements PSCo will make cash payments or billing credits to certain of the complaining customers totaling approximately $1.5 million. The settlements also provide for revisions to the base demand and energy rate filed in the wholesale electric rate case. PSCo and the other parties are negotiating the detailed settlement provisions, which are subject to FERC approval.

PSCo had a retail incentive cost adjustment (ICA) cost recovery mechanism in place for periods prior to calendar 2003. The CPUC conducted a proceeding to review and approve the incurred and recoverable 2001 costs under the ICA. In April 2003, the CPUC Staff and an intervenor filed testimony recommending disallowance of fuel and purchased energy costs, which, if granted, would result in a $30 million reduction in recoverable 2001 ICA costs. On July 10, 2003, a stipulation and settlement agreement was filed with the CPUC, which resolved all issues. Under the stipulation and settlement agreement, the recoverable costs under the ICA for the years 2001 and 2002 will be reduced by approximately $1.6 million. Additional evaluation of 2002 recoverable ICA costs will be conducted in a future CPUC proceeding. The resulting impact on the reset of the allowed cost recovery and cost sharing under the ICA for 2002 was not significant. In addition, the stipulation and settlement agreement provides for a prospective rate design adjustment related to the maximum allowable natural gas hedging costs that will be a part of the electric commodity adjustment for 2004 and is expected to reduce 2004 rates by an estimated $4.6 million. The stipulation and settlement agreement was approved by the CPUC in September 2003.

At September 30, 2003, PSCo has recorded its deferred fuel and purchased energy costs based on the expected rate recovery of its costs as filed in the above rate proceedings, without the adjustments proposed by various parties. Pending the outcome of these regulatory proceedings, we cannot at this time determine whether any customer refunds or disallowances of PSCo s deferred costs will be required other than as discussed above.

Electric Department Earnings Test Proceedings PSCo has filed its annual electric department earnings test reports for calendar 2001 and 2002. In both years, PSCo did not earn above its allowed authorized return on equity and, accordingly, has not recorded any refund obligations. In the 2001 proceeding, the Office of Consumer Counsel has proposed that the $10.9 million gain on the sale of the Boulder Hydroelectric Project be excluded from 2001 earnings and that possible refund of the gain be addressed in a separate proceeding. In the 2002 proceeding, the CPUC has opened a docket to consider whether PSCo s cost of debt has been adversely affected by the financial difficulties at NRG and, if so, whether any adjustments to PSCo s cost of capital should be made. The 2002 proceeding has been set for hearing in August 2004.

Wholesale General Rate Case On June 19, 2003, PSCo filed a wholesale electric rate case with the FERC, proposing to increase the annual electric sales rates charged to wholesale customers, other than Cheyenne Light Fuel & Power Co., our wholly owned subsidiary, by approximately $9 million. Several wholesale customers intervened protesting the proposed increase. On August 1, 2003, PSCo submitted a revised filing correcting an error in the calculation of income tax costs. The revised filing requests an approximately $2 million annual increase with new rates effective in January 2004, subject to refund. In August 2003, PSCo reached a settlement in principle in this case and the separate wholesale fuel clause cases.

Home Builders Association of Metropolitan Denver In February 2001, Home Builders Association of Metropolitan Denver (HBA) sought an award in the amount of $13.6 million for PSCo s failure to update its extension policy construction allowances from 1996 to 2002 under its tariff. An administrative law judge had ruled in January 2002 that HBA s claims were barred. The CPUC reversed that decision and remanded the case. On May 15, 2003, an administrative law judge issued a recommended decision. On the remanded issues, the judge determined the HBA is able to seek an award of reparations on behalf of its member homebuilders. However, the judge further determined the construction allowance applied by PSCo from 1996 through 2002 was neither excessive nor discriminatory, and that HBA failed to meet its burden to show that its method of calculating reparations for the period 1996 through 2002 is proper.

On August 27, 2003, the CPUC issued its ruling with respect to this matter and on September 24, 2003 adopted a written order in this proceeding. According to the CPUC decision:

PSCo should have been required to change its construction allowance from $360 to $381 as a result of the final determination in Phase I of its 1997 general rate case;

PSCo should file a plan to pay reparations to HBA members based on a revised $381 construction allowance for the period February 24, 1999 through May 31, 2002. The plan should take into account the most cost-effective way to reduce the burden of making detailed transaction-specific calculations versus a more general approach that does not unreasonably compromise the level of each refund;

Interest should be applied based on the customer deposit rate; and

PSCo over earned during the relevant time period and is prohibited from future recovery of the reparation costs.

The level of reparations based on a $381 construction allowance is not known at this time. However, management expects that such reparations are likely to be less than $1.5 million. PSCo and HBA have both requested rehearing of the August 27, 2003 CPUC order.

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Pacific Northwest Power Market A complaint has been filed at the FERC requesting that the agency set for investigation, pursuant to Section 206 of the Federal Power Act, the justness and reasonableness of the rates of wholesale sellers in the spot markets in the Pacific Northwest, including PSCo. The FERC decided to hold a preliminary evidentiary hearing to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. Such hearing was held before an administrative law judge of the FERC in August 2001. The administrative law judge recommended that the FERC conclude that the rates charged were not unjust and unreasonable, and accordingly, that there should be no refunds. On June 25, 2003, the FERC terminated the proceeding without refunds or ordering further proceedings.

FERC Investigation Against All Wholesale Electric Sellers/ California Refund Proceedings On June 25, 2003, the FERC issued a series of orders addressing the California electricity markets. Two of these were show cause orders. In the first show cause order, the FERC found that twenty-four entities may have worked in concert through partnerships, alliances or other arrangements to engage in activities that constitute gaming and/or anomalous market behavior. The FERC initiated the proceedings against these twenty-four entities requiring that they show cause why their behavior did not constitute gaming and/or anomalous market behavior. PSCo was not named in this order. In a second show cause order, the FERC indicated that various California parties, including the California Independent System Operator (CAISO), have alleged that forty-three entities individually engaged in one or more of seven specific types of practices that the FERC has identified as constituting gaming or anomalous market behavior within the meaning of the CAISO and California Power Exchange tariffs. PSCo was listed in an attachment to that show cause order as having been alleged to have engaged in one of the seven identified practices, namely circular scheduling. In the second show cause order, the FERC required the CAISO to provide the named entities with all of the specific transaction data for each of the seven practices. The CAISO provided that information on July 16, 2003. This data does not list PSCo as among the entities that allegedly engaged in circular scheduling. PSCo may have been named in the show cause order because of a trader telephone conversation transcript that PSCo had previously submitted to the FERC. This transcript was cited in witnesses testimony filed with the FERC. The circular scheduling reference in the transcript was by a trader from another company discussing a transaction that did not involve PSCo. On August 29, 2003, the FERC Trial Staff filed a motion to dismiss PSCo from the show cause proceeding. Various California parties have opposed the motion to dismiss. They have also requested rehearing of the FERC s show cause orders contending that the FERC should have named PSCo in the show cause orders as an entity that had engaged in (i) a load shift transaction and (ii) a partnership that constituted gaming. PSCo has answered both the request for rehearing and the California parties opposition to FERC Trial Staff s motion to dismiss.

SPS

SPS Texas Fuel Reconciliation, Fuel Factor and Fuel Surcharge Application In June 2002, SPS filed an application for the PUCT to retrospectively review the operations of the utility s electric generation and fuel management activities. In this application, SPS filed its reconciliation for electric generation and fuel management activities, totaling approximately $608 million, from January 2000 through December 2001. In May 2003, a stipulation was approved by the PUCT. The stipulation resolves all issues regarding SPS fuel costs and wholesale trading activities through December 2001. SPS will withdraw, without prejudice, its request to share in 10 percent of margins from certain wholesale non-firm sales. SPS will recover $1.1 million from Texas customers for the proposed sharing of wholesale non-firm sales margins. The parties agreed that SPS would reduce its December 2001 fuel under-recovery balances by $5.8 million. Including the withdrawal of proposed margin sharing of wholesale non-firm sales, the net impact to SPS deferred fuel expense, before tax, is a reduction of $4.7 million.

In May 2003, SPS proposed to increase its voltage-level fuel factors to reflect increased fuel costs since the time SPS current fuel factors were approved in March 2002. The proposed fuel factors are expected to increase Texas annual retail revenues by approximately $60.2 million.

SPS also reported to the PUCT that it has under-collected its fuel costs under the current Texas retail fixed fuel factors. In the same May 2003 application, SPS proposed to surcharge $13.2 million and related interest for fuel cost under-recoveries incurred through March 2003. In June 2003, the administrative law judge approved the increased fuel factors on an interim basis subject to hearings and completion of the case. The increased fuel factors became effective in July 2003. In July 2003, a unanimous settlement was reached adopting the surcharge and providing for the implementation of an expedited procedure for revising the fixed fuel factors on a semi-annual basis. The surcharge will be collected from customers over an eight-month period. In August 2003, the PUCT approved the settlement and the new proposed fuel cost recovery process and the surcharge became effective in September 2003. The Texas retail fuel factors will change each November and May based on the projected cost of natural gas. Revenues will continue to be reconciled to fuel costs in accordance with Texas law.

In July 2003, SPS filed a second fuel cost surcharge factor application in Texas to recover an additional $26 million of fuel cost under-recoveries accrued during April through June 2003. In August 2003, the parties to the case filed a stipulation resolving various issues. The stipulation provided approval of SPS modified request to surcharge $15.7 for the months April 2003 and May 2003 over twelve months, beginning with the November 2003 billing cycle. The stipulation was approved by the PUCT in October 2003.

In November 2003, SPS submitted a third fuel cost surcharge factor application in Texas to recover an additional $25 million of fuel cost under recoveries accrued during June through September 2003. If approved, the proposed surcharge will go into effect after the first surcharge is completed and will continue for 12 months beginning in May 2004. This case is pending review and approval by the PUCT.

SPS New Mexico Fuel Reconciliation and Fuel Factor Application On December 17, 2001, SPS filed an application with the NMPRC seeking approval of continued use of its fuel and purchased power cost adjustment using a monthly adjustment factor, authorization to implement the proposed monthly factor on an interim basis and approval of the reconciliation of its fuel and purchase power adjustment clause collections for the period October 1999 through September 2001. In January 2002, the NMPRC authorized SPS to implement a monthly adjustment factor on an interim basis beginning with the February 2002 billing cycle.

On May 27, 2003, a hearing examiner for the New Mexico Public Regulatory Commission (NMPRC) issued a recommended decision on SPS s fuel proceeding approving SPS utilizing a monthly fuel factor. SPS had been utilizing an annual fuel factor, which had allowed significant under-collections. The decision denied the intervenors request that all margins from off-system sales be credited to ratepayers. On August 19, 2003, the NMPRC approved the hearing examiner s recommended decision. In accordance with NMPRC regulations, SPS must file its next New Mexico fuel factor continuation case no later than August 2005.

Golden Spread Electric Cooperative, Inc. In October 2001, Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a complaint and request for investigation against SPS before the FERC. Golden Spread alleged SPS had violated provisions of a Commitment and Dispatch Service Agreement pursuant to which SPS conducts joint dispatch of SPS and Golden Spread resources. SPS filed a counter complaint against Golden Spread in which it has alleged that Golden Spread has failed to adhere to certain requirements of the Commitment and Dispatch Service Agreement. In May 2003, SPS and Golden Spread reached a settlement that was approved by the FERC in July 2003. The $5 million accrued costs for payments under the settlement have been deferred by SPS as they are for economic purchased energy and are recoverable from SPS customers through the respective jurisdictional fuel and purchased power cost recovery mechanisms.

Merger Agreement As a part of the NCE and NSP merger approval process in Texas, SPS agreed to:

guarantee annual merger savings credits of approximately $4.8 million and amortize merger costs through 2005;

retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and

comply with various service quality and reliability standards, covering service installations and upgrades, light replacements, customer service call centers and electric service reliability.

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

guarantee annual merger savings credits of approximately $780,000 and amortize merger costs through December 2004;

share net non-fuel operating and maintenance savings equally among retail customers and shareholders;

retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and

not pass along any negative rate impacts of the merger.

SPS Texas Transition to Competition Cost Recovery Application In December 2001, SPS filed an application with the PUCT to recover $20.3 million in costs from the Texas retail customers associated with the transition to competition. These costs were incurred to position SPS for retail competition, which was eventually delayed for SPS. The filing was amended in March 2002 to reduce the recoverable costs by $7.3 million, which was associated with over-earnings recognized for the 1999 annual report. The PUCT approved SPS using the 1999 annual report over-earnings to offset the claims for reimbursement of transition to competition costs. This reduced the requested net collection in Texas to $13.0 million. In April 2002, a unanimous settlement agreement was reached. Final approval by the PUCT was received in May 2002. The stipulation provides for the recovery of $5.9 million through an incremental cost recovery rider and the capitalization of $1.9 million for metering equipment. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million in the first quarter of 2002. Recovery of the $5.9 million began in July 2002.

New Mexico Renewable Energy Requirements In December 2002, the NMPRC adopted new regulations requiring investor-owned utilities operating in New Mexico to promote the use of renewable energy technologies by procuring at least ten percent of their New Mexico retail energy requirements from renewable resources by no later than 2011.

Billing Practices Investigation Beginning in April 2003, SPS estimated electricity usage for approximately 9,500 customer accounts in two New Mexico cities. Estimated bills were sent to these customers for between two and five months. On September 25, 2003, the NMPRC entered an order opening an investigation into SPS practices regarding estimated billing. The commission ordered SPS to show cause why it is not in violation of the commission rule that limits the use of estimated meter readings.

As part of the September 25, 2003 order, the NMPRC also implemented temporary billing measures for customers whose bills were estimated. The temporary billing measures: (i) require SPS to apply the lowest fuel and purchased power cost adjustment factor that was applicable during the period when bills were being estimated, (ii) allow customers 6 months to pay bills in full without additional charges or disconnection, (iii) prohibit disconnection of service until November 1, 2003 for any customer that received an estimated bill, (iv) require SPS to work with the NSPRC staff on a written explanation of the fuel calculation used under the order, and (v) order SPS to report the amount of fuel and purchased power costs foregone as a result of the interim relief, which amount SPS will not be allowed to recoup from customers. The proceedings have been referred to a hearing examiner.

Cheyenne

Cheyenne Purchased Power Costs In March 2001, Cheyenne requested an increase in retail electric rates to provide for recovery of increasing power costs. As a result of the significant increase in electric energy costs since late February 2001, Cheyenne under recovered its costs under its electric cost adjustment (ECA) mechanism. On May 25, 2001, the WPSC approved a Stipulation Agreement between Cheyenne and intervenors in connection with a proposed increase in rates charged to Cheyenne s retail customers to recover increased power costs.

The Stipulation provides for an ECA rate structure with a fixed energy supply rate for Cheyenne s customers through 2003; the continuation of the ECA with certain modifications, including the amortization through December 2005 of unrecovered costs incurred during 2001 up to the agreed upon fixed supply rates;

and agreement that Cheyenne s energy supply needs will be provided, in whole or in part, by PSCo in accordance with wholesale tariff rates to be approved by the FERC. The estimated retail rate increases under the Stipulation would provide recovery of an additional $18 million (in comparison to prior rate levels) through the remainder of 2001 and a total of $28 million for each of the years 2002 and 2003. In 2004 and 2005, Cheyenne will return to requesting recovery of its actual costs incurred plus the outstanding balance of any deferral from earlier years. New cost levels consistent with the Stipulation Agreement has been reflected in Cheyenne s expenses, and in deferred costs based on current ECA recovery levels, with an effective date of June 1, 2001, and retroactive adjustments back to the date of the increase in costs on February 25, 2001.

For more information on regulatory matters, see Management s Discussion and Analysis of Financial Condition and Results of Operations. See also the discussion regarding TRANSLink Transmission Company LLC under Electric Utility Operations.

Electric Utility Operations

Competition and Industry Restructuring

Retail competition and the unbundling of regulated energy service could have a significant financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. The restructuring may have a significant financial impact on our financial position, results of operations and cash flows and our utility subsidiaries cannot predict when they will be subject to changes in legislation or regulation, nor can they predict the impacts of such changes on their financial position, results of operations or cash flows. We believe that the prices our utility subsidiaries charge for electricity and the quality and reliability of their service currently place them in a position to compete effectively in the energy market.

Retail Business Competition The retail electric business faces increasing some competition as industrial and large commercial customers have some ability to own or operate facilities to generate their own electric energy. In addition, customers may have the option of substituting other fuels, such as natural gas for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost environment. While each of our utility subsidiaries face these challenges, these subsidiaries believe their rates are competitive with currently available alternatives. Our utility subsidiaries are taking actions to lower operating costs and are working with their customers to analyze energy efficiency and load management programs in order to better position our utility subsidiaries to more effectively operate in a competitive environment.

Wholesale Business Competition The wholesale electric business faces increasing competition in the supply of bulk power, due to federal and state initiatives to provide open access to utility transmission systems. Under current FERC rules, utilities are required to provide wholesale open-access transmission services and to unbundle wholesale merchant and transmission operations. Our utility subsidiaries are operating under a joint tariff in compliance with these rules. To date, these provisions have not had a material impact on the operations of our utility subsidiaries.

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

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

Some states had begun to allow retail customers to choose their electricity supplier, and many other states were considering retail access proposals. However, the experience of the State of California in instituting

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competition, as well as the bankruptcy filing of Enron Corporation in 2001, have caused indefinite delays in most industry restructuring.

We cannot predict the outcome of restructuring proceedings in the electric utility jurisdictions we serve at this time. The resolution of these matters may have a significant impact on our financial position, results of operations and cash flows.

FERC Restructuring During 2001 and 2002 and the first nine months of 2003, the FERC issued several industry-wide orders impacting (or potentially impacting) our operating companies and NRG. In addition, our utility subsidiaries submitted proposals to the FERC that could impact future operations, costs and revenues.

Section 206 Investigation Against All Wholesale Electric Sellers In November 2001, the FERC issued an order under Section 206 of the Federal Power Act initiating a generic investigation proceeding against all jurisdictional electric suppliers making sales in interstate commerce at market based rates. NSP-Minnesota, PSCo, SPS and certain NRG affiliates had previously received FERC authorization to make wholesale sales at market based rates, and have been engaged in such sales subject to rates on file at the FERC. The order proposed that all wholesale electric sales at market based rates conducted starting 60 days after publication of the FERC order in the Federal Register would be subject to refund conditioned on factors determined by the FERC.

Several parties filed requests for rehearing, arguing the November 2001 order was vague and would require the affected utilities to conditionally report future revenues and earnings. In late November 2001, the FERC issued a notice delaying the effective date of the subject to refund condition, but subject to further investigation and proceedings. Comments were filed by numerous parties in January, 2002 and reply comments were filed in February of that year. Further, the FERC Staff convened a conference in this proceeding in February of 2002. The FERC has not yet acted on the matter.

MISO Operations and Electric Market Initiative In compliance with a condition in the January 2000 FERC order approving the Merger, NSP-Minnesota and NSP-Wisconsin entered into agreements to join the MISO in August 2000. In December 2000, the FERC approved the MISO as the first approved regional transmission organization (RTO) in the U.S., pursuant to FERC Order 2000. On February 1, 2002, the MISO began interim operations, including regional transmission tariff administration services for the NSP-Minnesota and NSP-Wisconsin electric transmission systems. NSP-Minnesota and NSP-Wisconsin have received all required regulatory approvals to transfer functional control of their high voltage (100 kV and above) transmission systems to the MISO when the MISO is fully operational. The MISO will then control the operations of these facilities and the facilities of neighboring electric utilities. The MISO also submitted an application to the FERC for approval of the business combination of the MISO and the SPP. However, in March 2003, MISO and SPP mutually terminated their planned combination.

In October 2001, the FERC issued an order in the separate proceeding to establish the initial MISO regional transmission tariff rates, ruling that all transmission services (with limited exceptions) in the MISO region must be subject to the MISO regional tariff and administrative surcharges to prevent discrimination between wholesale transmission service users. The FERC order unilaterally modified the agreement with the MISO signed in August 2000. The FERC order increased wholesale transmission costs to NSP-Minnesota and NSP-Wisconsin by up to $9 million per year.

On July 25, 2003, MISO filed proposed changes to its regional open access transmission tariff to implement a new Transmission and Energy Markets Tariff (TEMT) that would establish certain wholesale energy and transmission service rates based on locational marginal cost pricing (LMP) to be effective in 2004. NSP-Minnesota and NSP-Wisconsin presently receive transmission services from MISO for service to their retail loads and would be subject to the new tariff, if approved by the FERC. After numerous parties, including several states, filed protests to the proposal, MISO filed on October 17, 2003 to withdraw the TEMT without prejudice to refiling. The FERC issued an order approving the withdrawal and provided guidance on MISO s proposals on October 29, 2003. MISO is now starting the stakeholder consultation process to prepare and submit a revised TEMT in 2004. Management believes any new tariff, if approved by the FERC, could

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have a material effect on wholesale power supply or transmission service costs to NSP-Minnesota and NSP-Wisconsin.

TRANSLink Transmission Company LLC In September 2001, our operating companies joined a proposal with several other electric utilities in the U.S. Mid-continent region to form TRANSLink Transmission Company LLC (TRANSLink), an independent transmission company (ITC) which would own and/or operate electric high voltage transmission facilities within a FERC-approved RTO. Initially, the applicants propose that the high voltage transmission systems of NSP-Minnesota and NSP-Wisconsin be under the functional control of TRANSLink under an operating agreement between the utilities and TRANSLink, which would then be a member of the Midwest ISO RTO. The electric transmission facilities of SPS would participate upon the merger of the MISO and SPP. PSCo would also be operated by TRANSLink, but would not initially be part of an RTO because no FERC-approved RTO is operational in the western United States at this time.

TRANSLink would pay our operating companies a fee for use of their transmission systems, determined on a regulated cost of service basis, and would collect its administrative costs through transmission rate surcharges. The TRANSLink participants argue that RTO participation through the TRANSLink ITC would comply with FERC Order 2000 at a lower cost than RTO participation as vertically integrated utilities. Under the proposal, TRANSLink will be responsible for planning, managing and operating both local and regional transmission assets. TRANSLink will also construct and own new transmission system additions. TRANSLink will collect the revenue for the use of our transmission assets through a FERC-approved, regulated cost-of-service tariff and will collect its administrative costs through transmission rate surcharges. Transmission service pricing will continue to be regulated by the FERC, but construction and permitting approvals will continue to rest with regulators in the states served by TRANSLink.

In May 2002, the participants formed TRANSLink Development Company, LLC, which is responsible for pursuing the actions necessary to complete the regulatory approval of TRANSLink Transmission Company, LLC.

In April 2002, the FERC gave conditional approval for the applicants to transfer ownership or operations of their transmission systems to TRANSLink and to form TRANSLink as an independent transmission company operating under the umbrella RTO organization of MISO. The FERC conditioned TRANSLink s approval on the resubmission of its tariff as a separate rate schedule to be administered by the MISO. TRANSLink Development Company made this rate filing in October 2002. In October 2002, TRANSLink Development also entered into a definitive agreement with the MISO, whereby TRANSLink will contract with the MISO for certain required RTO functions and services. On November 1, 2002, the FERC issued its order supporting the approval of the formation of TRANSLink. The FERC also clarified several issues covered in its April 2002 order. In December 2002, the FERC approved the TRANSLink rate schedule subject to refund, and required TRANSLink to engage in settlement discussions on several items. TRANSLink filed a settlement agreement with the FERC in April, 2003 that was approved by the FERC in July 2003. In January 2003, the FERC also approved TRANSLink s contractual relationship with the Midwest Independent System Operator. This contract delineates the role that TRANSLink will have within the TRO. Finally, in January 2003, TRANSLink also identified its nine member independent Board of Directors. The establishment of an independent board is required to satisfy Order 2000 obligations.

Several state approvals also would be required to implement the proposal, as well as SEC approval. State applications were made in late 2002 and early 2003. In June 2003, the MPUC held a hearing on the TRANSLink application, filed in December 2002. At the hearing, the MPUC deferred any decision. Instead, the MPUC indicated NSP-Minnesota could submit a supplemental or revised application to explain certain recent changes to the proposal and to respond to a number of issues and questions posed by the MPUC advisory staff and other parties. On November 3, 2003, NSP-Minnesota submitted a status report to the MPUC indicating the participants are evaluating the TRANSLink proposal in light of recent events and would provide a further report within 30 days. Similar filings in North Dakota and Wisconsin are not contested, but have not been approved.

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In 2002, SPS filed for PUCT and NMPRC approval to transfer functional control of its electric transmission system to TRANSLink, of which SPS would be a participant. In March 2003, the Southwest Power Pool and the MISO cancelled their planned merger to form a large midcontinent RTO. This development materially impacted SPS applications in Texas and New Mexico. SPS requested the cases be dismissed without prejudice while it evaluates possible RTO arrangements for the SPS system. We are considering these developments, as well as the proceedings in process in other jurisdictions, to evaluate the possible future role of TRANSLink in providing transmission operations service for the Xcel Energy system. As of September 30, 2003, Xcel Energy s subsidiaries had deferred approximately $5 million of TRANSLink-related costs based on anticipated recovery in future rates.

Standards of Conduct Rulemaking In October 2001, the FERC issued proposed rules which would substantially increase the functional separation requirements under existing FERC rules (Orders No. 497 and 889) between the regulated electric and natural gas transmission functions of our operating companies and West Gas Interstate, and the wholesale electric and natural gas marketing functions of PSCo, NSP-Minnesota, NRG and e prime. The proposed rules, if adopted, would require substantially increased functional separation, causing a loss of integration efficiencies and thus higher costs. In December 2001, we and numerous other parties filed comments opposing the proposed rules. In May 2002, the FERC Staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. No final rule has been issued.

Standard Market Design Rulemaking In July 2002 the FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD) rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale markets operate throughout the United States. The proposal expands the FERC s intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The rule contemplates that all wholesale and retail customers will be on a single network transmission service tariff. The rule also contemplates the implementation of a bid based system for buying and selling energy in wholesale markets. The market will be administered by RTOs or Independent Transmission Providers. RTOs will also be responsible for putting together regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring that individual participants do not exercise unlawful market power. Comments to the rules were filed in the fourth quarter of 2002, with replies and further comment scheduled for the first quarter of 2003. In April 2003, the FERC issued a whitepaper describing proposed changes to the proposed SMD rules based on public comments. Pending legislation in Congress would forbid the FERC from implementing the SMD rules for several years, but that legislation has not been adopted. At this time it is unclear when or if the final SMD rules may be implemented. However, for the NSP-Minnesota and NSP-Wisconsin systems, the Midwest ISO RTO separately proposed in July 2003 to implement a market design similar to the one proposed by the FERC rules. In September 2003, after the August 14, 2003 northeast blackout, the Midwest ISO announced plans for a phased implementation of the new market design in 2004. The PSCo and SPS systems are not affected by the Midwest ISO proposal.

NSP-Minnesota

Minnesota Restructuring In 2001, the Minnesota Legislature passed an energy security bill that includes provisions that are intended to streamline the siting process of new generation and transmission facilities. It also includes voluntary benchmarks for achieving renewable energy as a portion of the utility supply portfolio. There is unlikely to be any further action on restructuring in 2003.

North Dakota Restructuring In 1997, the North Dakota Legislature established by statute, an Electric Utility Competition Committee (EUC). The EUC was given six years to perform its research and submit its final report on restructuring, competition, and service territory reforms. To date, the committee has focused on the study of the state s current tax treatment of the electric utility industry, primarily in the transmission and distribution functions. The report presented to the legislative council in early 2001 did not include recommendations to change the current tax structure. However, the legislature, without recommendation from the EUC, overhauled the application of the coal severance and coal conversion taxes primarily to improve the competitive status of North Dakota lignite for generation. During 2002, the committee continued its review. No legislation has resulted from the review.

NSP-Wisconsin

Wisconsin Restructuring The State of Wisconsin continued its incremental approach to industry restructuring by passing legislation in 2001 that reduced the wholesale gross receipts tax on the sale of electricity by 50 percent starting in 2003. This legislation eliminates the double taxation on wholesale sales from non-utility generators, and should encourage the development of merchant plants by making sales from independent power producers more competitive. Additional legislation was passed that enables regulated utilities to enter into leased generation contracts with unregulated generation affiliates. The new legislation provides utilities a new financing mechanism and option to meet their customers energy needs. In 2002, the PSCW approved the first power plant proposal utilizing the new leased generation contract arrangement. While industry-restructuring changes continue in Wisconsin, the movement towards retail customer choice has virtually stopped.

Michigan Restructuring Since January 1, 2002, NSP-Wisconsin has been providing its Michigan electric customers with the opportunity to select an alternative electric energy provider. This action was required by Michigan s Customer Choice and Electricity Reliability Act, which became law in June 2002. NSP-Wisconsin developed and successfully implemented internal procedures, and obtained MPSC approval for these procedures to meet the January 1, 2002 deadline. Key elements of internal procedures include the development of retail open access tariffs and unbundled billing, environmental and fuel disclosure information, and a code of conduct compliance plan.

PSCo

Colorado Restructuring During 1998, a bill was passed in Colorado that established an advisory panel to conduct an evaluation of electric industry restructuring and customer choice. During 1999, this panel concluded that Colorado would not significantly benefit from opening its markets to retail competition. There was no legislative action with respect to restructuring in Colorado during the 2000, 2001, 2002 and the first nine months of 2003 legislative sessions. No legislative action is expected in the remainder of 2003.

SPS

New Mexico Restructuring In March 2001, the state of New Mexico enacted legislation that delayed customer choice until 2007 and amended the Electric Utility Restructuring Act of 1999. SPS has requested recovery of its costs incurred to prepare for customer choice in New Mexico of approximately $5.1 million. A decision on this and other matters is pending before the NMPRC. SPS expects to receive regulatory recovery of these costs through a rate rider in the next New Mexico rate case filed.

Texas Restructuring In June 2001, the Governor of Texas signed legislation postponing the deregulation and restructuring of SPS until at least 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition beginning January 2002. Under the newly-adopted legislation, prior PUCT orders issued in connection with the restructuring of SPS will be considered null and void. SPS restructuring and rate unbundling proceedings in Texas have been terminated. In addition, under the new legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before September 1, 2001, to comply with SB-7. SPS filed an application with the PUCT, requesting a rate rider to recover these costs incurred preparing for customer choice of approximately $20.3 million. These costs were incurred to position SPS for retail competition, which was eventually delayed for SPS. The filing was amended in March 2002 to reduce the recoverable costs by $7.3 million, which were associated with over-earnings for the calendar year 1999. The PUCT approved SPS using the 1999 over-earnings to offset the claims for reimbursement of transition to competition costs. This reduced the requested net collection in Texas to $13.0 million. In April 2002, a unanimous settlement agreement was reached. Final approval by the PUCT was received in May 2002. The stipulation provides for the recovery of $5.9 million through an incremental cost recovery rider and the capitalization of $1.9 million for metering equipment. Based on the settlement

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agreement, SPS wrote off pretax restructuring costs of approximately $5 million in the first quarter of 2002. Recovery of the $5.9 million began in July 2002.

For more information on restructuring in Texas and New Mexico, see Note 15 to the audited consolidated financial statements.

Kansas Restructuring During the 2001 legislative session, several restructuring-related bills were introduced for consideration by the state legislature, but to date, there has been no restructuring mandate in Kansas.

Oklahoma Restructuring The Electric Restructuring Act of 1997 was enacted in Oklahoma during 1997. This legislation directed a series of studies to define the orderly transition to consumer choice of electric energy supplier by July 1, 2002. In 2001, Senate Bill 440 was signed into law to formally delay electric restructuring until restructuring issues could be studied further and new enabling legislation could be enacted. Senate Bill 440 established the Electric Restructuring Advisory Committee and directed the committee to complete an interim report on the state s transmission infrastructure needs by December 31, 2001. The Advisory Committee submitted this report to the Governor and Legislature on December 31, 2001. During 2002 and the first nine months of 2003, there was no action taken by the Legislature as a result of this report. Oklahoma continues to delay retail competition.

Other

Wyoming Restructuring There were no electric industry restructuring legislation proposals introduced in the legislature during 2000, 2001, 2002 and the first nine months of 2003.

Capacity and Demand

Assuming normal weather during 2003, system peak demand and the net dependable system capacity for our electric utility subsidiaries are projected below. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin are managed as an integrated system (referred to as the NSP System). The system peak demand for each of the last three years and the forecast for 2003 are listed below.

System Peak Demand Forecast

Operating Company	2000	2001	2002	2003 Forecast
			(in megawatts)	
NSP System	7,936	8,344	8,259	8,090
PSCo	5,406	5,644	5,8724	5,947
SPS	3,870	4,080	4,018	4,052

During the first six months of 2003, the peak demand for the NSP System was 7,760 megawatts which occurred on June 24, 2003; the peak demand for PSCo was 5,513 megawatts, which occurred on May 29, 2003; and the peak demand for SPS was 4,162 megawatts, which occurred on June 23, 2003. The peak demand for the NSP System, PSCo and SPS all typically occur in the summer. The 2002 system peak demand for the NSP System occurred on July 30, 2002. The 2002 system peak demand for PSCo occurred on July 18, 2002. The 2002 system peak demand for SPS occurred on August 1, 2002.

Energy Sources

Our utility subsidiaries expect to use the following resources to meet their net dependable system capacity requirements:

our electric generating stations;

purchases from other utilities, independent power producers and power marketers;

demand-side management options; and

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phased expansion of existing generation at select power plants.

Purchased Power

Our electric utility subsidiaries have contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. Capacity, typically measured in kilowatts or megawatts, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in kilowatt-hours or megawatt-hours, is a measure of the amount of electricity produced from a particular generating source over a period of time. Purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

Our utility subsidiaries also make short-term and non-firm purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to provide each utility s reserve obligation, to obtain energy at a lower cost than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

NSP System Resource Plan

In December 2002, NSP-Minnesota filed its Resource Plan with the MPUC for 2003 to 2017. The plan describes how we intend to meet the energy needs of the NSP System. The plan contains conservation programs to reduce NSP System s peak demand and conserve overall electricity use, an approximate schedule of power purchase solicitations to meet increasing demand, and programs and plans to maintain the reliable operations of existing resources. Critical to NSP-Minnesota s Resource Plan is the role nuclear power at the Prairie Island and Monticello plants will play in future years. Last spring, the MPUC suspended the resource plan proceeding while the issue of spent nuclear fuel storage and continued operation of NSP-Minnesota s nuclear plants was considered by the Minnesota Legislature. In May 2003, the Minnesota Legislature and Governor authorized additional spent fuel storage so that the Prairie Island plant can operate until its federal licenses expire in 2013 and 2014. The new legislation also provides a process in which the MPUC can determine if it is in the state s interest to allow the plants to operate beyond their current licensed lives. On September 10, 2003, NSP-Minnesota provided the MPUC with a resource plan update and requested permission to refile a new plan in the fall of 2004 due to the legislative changes and the passage of time. The request is pending.

PSCo Resource Plan

PSCo estimates it will purchase approximately 31 percent of its total electric system energy input for 2003. Approximately 44 percent of the total system capacity for the summer 2003 system peak demand for PSCo will be provided by purchased power.

PSCo estimates that customers will require approximately 1,600 megawatts of new electricity generating capacity by 2013 and more than 3,100 MW overall. The increased demand for electricity elevates the need for more base-load generating capacity. Base-load generation runs continuously at close to full power except during scheduled maintenance or unexpected outages.

Approximately 1,500 MW of the resource need could be met by renewing contracts with independent power providers, but the remaining 1,600 MW of anticipated demand requires the addition of new generating capacity.

Xcel Energy had committed to present a least cost resource plan (LCP) to meet the demand on October 31, 2003. However, on September 25, 2003, Xcel Energy requested a six-month extension to present its LCP by April 2004. More time is needed to more fully explore the low-cost option of adding more base-load, coal-fired generating capacity to PSCo s system. PSCo s LCP will recommend to the CPUC the most cost-effective mix of resources to meet future demand. The plan will explore a variety of generating

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technologies and fuels, including coal, natural gas, wind and conservation. The blueprint will also outline preferred methods to acquire the resources, including a competitive bidding process.

Purchased Transmission Services

Our utility subsidiaries have contractual arrangements with regional transmission service providers to deliver power and energy to the subsidiaries native load customers (retail and wholesale load obligations with terms of more than one year). Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved, although some agreements may base charges on the amount of metered energy delivered. Network transmission services include a charge for the metered demand at the delivery point at the time of the provider s monthly transmission system peak, usually calculated as a 12-month rolling average.

Fuel Supply and Costs

The following tables present the delivered cost per million British thermal units (MMBtu) of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels during such years:

	Coal*		Nuclear		
NSP System generating plants:	**Cost**	**Percent**	**Cost**	**Percent**	**Average Fuel Cost**
First Six Months of 2003	$0.99	61%	$0.44	31%	$0.79
2002	$0.96	59%	$0.46	38%	$0.81
2001	$0.96	62%	$0.47	35%	$0.86
2000	$1.11	60%	$0.45	36%	$0.91

* Includes refuse-derived fuel and wood

	Coal		Gas		
PSCo generating plants:	**Cost**	**Percent**	**Cost**	**Percent**	**Average Fuel Cost**
First Six Months of 2003	$0.90	84%	$4.26	16%	$1.44
2002	$0.91	79%	$2.25	21%	$1.19
2001	$0.86	84%	$4.27	16%	$1.41
2000	$0.91	87%	$3.97	13%	$1.30

	Coal		Gas		
SPS generating plants:	**Cost**	**Percent**	**Cost**	**Percent**	**Average Fuel Cost**
First Six Months of 2003	$1.15	75%	$5.72	25%	$2.30
2002	$1.33	74%	$3.27	26%	$1.84
2001	$1.40	69%	$4.35	31%	$2.31
2000	$1.45	70%	$4.23	30%	$2.28

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin normally maintain between 30 and 45 days of coal inventory at each plant site. Estimated coal requirements at NSP-Minnesota s major coal-fired generating plants are approximately 12 million tons per year. NSP-Minnesota and NSP-Wisconsin have long-term contracts providing for the delivery of up to 100 percent of 2003 coal requirements and up to 58 percent of their 2004 requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather and availability of equipment.

NSP-Minnesota and NSP-Wisconsin expect that all of the coal they burn in 2003 will have a sulfur content of less than 1 percent. NSP-Minnesota and NSP-Wisconsin have contracts for a maximum of 41 million tons of low-sulfur coal for the next five years. The contracts are with two Montana coal suppliers and three Wyoming suppliers with expiration dates ranging between 2003 and 2007. NSP-Minnesota and

NSP-Wisconsin could purchase approximately 42 percent of coal requirements in 2004 if spot prices are more favorable than contracted prices.

NSP-Minnesota and NSP-Wisconsin s current fuel oil inventory is adequate to meet anticipated requirements for the remainder of 2003 and for 2004 and they also have access to the spot market to buy more oil as needed. NSP-Minnesota and NSP-Wisconsin use both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for power plants are procured under short- and intermediate-term contracts to provide an adequate supply of fuel.

To operate NSP-Minnesota s nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium- and long-term contracts for uranium, conversion and enrichment. Current contracts are flexible and cover 100 percent of uranium, conversion and enrichment requirements through the year 2005. These contracts expire at varying times between 2003 and 2006. The overlapping nature of contract commitments will allow NSP-Minnesota to maintain 50 percent to 100 percent coverage beyond 2002. NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Fuel fabrication is 100 percent committed through 2004 and 30 percent committed through 2010.

PSCo

PSCo s primary fuel for its steam electric generating stations is low-sulfur western coal. PSCo s coal requirements are purchased primarily under long-term contracts with suppliers operating in Colorado and Wyoming. During 2002, PSCo s coal requirements for existing plants were approximately 10.1 million tons, a substantial portion of which was supplied pursuant to long-term supply contracts. Coal supply inventories at June 30, 2003, were approximately 36 days usage, based on the average burn rate for all of PSCo s coal-fired plants.

PSCo operates the Hayden Station, and has partial ownership in the Craig Station, in Colorado. All of Hayden Station s coal requirements are supplied under a long-term agreement. Approximately 75 percent of PSCo s Craig Station coal requirements are supplied under two long-term agreements. Any remaining Craig Station requirements for PSCo are supplied through spot coal purchases.

PSCo has secured more than 75 percent of Cameo Station s coal requirements for the remainder of 2003 and for 2004. Any remaining requirements may be purchased from this contract or the spot market. PSCo has contracted for coal supplies to supply approximately 100 percent of the Cherokee and Valmont Stations projected requirements for the remainder of 2003 and for 2004.

PSCo has long-term coal supply agreements for the Pawnee and Comanche Stations projected requirements. Under the long-term agreements, the supplier has dedicated specific coal reserves at the contractually defined mines to meet the contract quantity obligations. In addition, PSCo has a coal supply agreement to supply approximately 60 percent of Arapahoe Station s projected requirements for the remainder of 2003 and for 2004. Any remaining Arapahoe Station requirements will be procured through spot purchases.

PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo s power plants are procured under short and intermediate-term contracts to provide an adequate supply of fuel.

SPS

SPS purchases all of its coal requirements for Harrington and Tolk electric generating stations from TUCO Inc., in the form of crushed, ready-to-burn coal delivered to SPS plant bunkers. For the Harrington station the coal supply contract expires in 2016 and the coal-handling agreement expires in 2004. For the Tolk station, the coal supply contract expires in 2017 and the coal-handling agreement expires in 2005. At June 30, 2003, coal inventories at each of the Harrington and Tolk sites were approximately 35 days supply. TUCO has a long-term coal supply agreement to supply approximately 100 percent of the projected requirements for the remainder of 2003 and for 2004 for Harrington Station and Tolk Station. TUCO has long-term contracts for the supply of coal in sufficient quantities to meet the primary needs of the Tolk station.

SPS has a number of short and intermediate-term contracts with natural gas suppliers operating in gas fields with long life expectancies in or near its service area. SPS also utilizes firm and interruptible transportation to minimize fuel costs during volatile market conditions and to provide reliability of supply. SPS maintains sufficient gas supplies under short and intermediate-term contracts to meet all power plant requirements; however, due to flexible contract terms, approximately 50 percent of SPS gas requirements during 2002 were purchased under spot agreements.

Trading Operations

We and our subsidiaries conduct various trading operations including the purchase and sale of electric capacity and energy. We use these trading operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances, and changes in fuel prices. Participation in short-term wholesale energy markets provides market intelligence and information that supports the energy management of each utility subsidiary. We reduce commodity price and credit risks by using physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. Optimizing the utility subsidiaries physical assets by engaging in short-term sales and purchase commitments results in lowering the cost of supply for our native customers and the capturing of additional margins from non-traditional customers. We and our subsidiaries also use these trading operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances and changes in fuel prices.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island 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 and are licensed to operate until 2013 and 2014, respectively. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive waste includes used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

Federal law places responsibility on each state for disposal of its low-level radioactive waste. Low-level radioactive waste from NSP-Minnesota s Monticello and Prairie Island nuclear plants is currently disposed of at the Barnwell facility, located in South Carolina (all classes of low-level waste), and the Clive facility, located in Utah (class A low-level waste only). Chem Nuclear is the owner and operator of the Barnwell facility, which has been given authorization by South Carolina to accept low-level radioactive waste from out of state. Envirocare, Inc. operates the Clive facility. NSP-Minnesota and Barnwell currently operate under an annual contract, while NSP-Minnesota uses the Envirocare facility through various low-level waste processors. NSP-Minnesota has low-level storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their licensed lives if off-site low-level disposal facilities were not available to NSP-Minnesota.

The federal government has the responsibility to dispose of, or permanently store, domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the United States Department of Energy (DOE) to implement a program for nuclear waste management. This includes the siting, licensing, construction and operation of a repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent storage or disposal facility by 1998. None of NSP-Minnesota s spent nuclear fuel has yet been accepted by the DOE for disposal. See Legal Proceedings and Note 19 to the audited consolidated financial statements for further discussion of this matter.

NSP-Minnesota has on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear plants. The Prairie Island plant is licensed by the federal Nuclear Regulatory Commission (NRC) to store up to 48 casks of spent fuel at the plant. In 1994, the Minnesota Legislature adopted a limit on dry cask storage of 17 casks for the entire state. The 17 casks, which stand outside the Prairie Island plant, are now full, and under the current configuration the storage pool within the plant would be full by 2007.

On May 29, 2003, the Minnesota Legislature enacted legislation which will enable NSP-Minnesota to store at least 12 more casks of spent fuel outside the Prairie Island plant, allowing spent-fuel storage there until our licenses with the NRC expire in 2013 and 2014. The legislation transfers from the Minnesota Legislature to the MPUC the primary authority concerning future spent-fuel storage issues and allows for the extension of the NRC licenses of the Prairie Island and the Monticello nuclear generating plants without the requirement of an affirmative vote from the Minnesota Legislature. 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. Nearly all of the cost increases to NSP-Minnesota from these required payments and funding commitments are expected to be recoverable in 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.

NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 1997, Private Fuel Storage, LLC (PFS) filed a license application with the NRC for a temporary storage site for spent nuclear fuel on the Skull Valley Indian Reservation in Utah. The NRC license review process includes formal evidentiary hearings before an Atomic Safety and Licensing Board (the ASLB) and opportunities for public input. Evidentiary hearings were held in 2000 and 2002, Most of the issues raised by opponents of the project have been favorably resolved or dismissed. On March 10, 2003, the ASLB ruled that the likelihood of certain aircraft crashes into the proposed facility was sufficiently credible that it would have to be addressed before the facility could be licensed and set forth a potential process for addressing this concern. PFS is currently evaluating this decision and awaiting ASLB decisions on the remaining five major issues expected in a few weeks. Due to uncertainty regarding NRC and other regulatory and governmental approvals, it is possible that this interim storage may be delayed or not available at all.

In February 2001, NSP-Minnesota signed a contract with Steam Generating Team Ltd. to perform engineering and construction services for the installation of replacement steam generators at the Prairie Island nuclear power plant. NSP-Minnesota is evaluating the economics of replacing two steam generators on unit 1 at the plant. NSP-Minnesota is taking steps to preserve the replacement option for as early as 2004. The total cost of replacing the steam generators is estimated to be approximately $132 million.

The NRC is engaged in various ongoing studies and rulemaking activities that may impose additional requirements upon commercial nuclear power plants. Management is unable to predict any new requirements or their impact on NSP-Minnesota s facilities and operations.

Nuclear Management Company

During 1999, NSP-Minnesota, Wisconsin Electric Power Co., Wisconsin Public Service Corp. and Alliant Energy Corp. established the Nuclear Management Company (NMC). Consumers Power joined the NMC during 2000, and transferred operating authority for the Palisades nuclear plant to the NMC in

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2001. The five affiliated companies own eight nuclear units on six sites, with total generation capacity exceeding 4,500 megawatts. We are currently a 20 percent owner of the NMC.

The NRC has approved requests by the NMC s affiliated utilities to transfer operating authority for their nuclear plants to the NMC, formally establishing the NMC as an operating company. The NMC manages the operations and maintenance at the plants, and is responsible for physical security. NMC responsibilities also include oversight of on-site dry storage facilities for used nuclear fuel at the Prairie Island nuclear plant. Utility plant owners, including us, continue to own the plants, control all energy produced by the plants and retain responsibility for nuclear liability insurance and decommissioning costs. Existing personnel continue to provide day-to-day plant operations, with the additional benefit of sharing ideas and operating experience from all NMC-operated plants for improved safety, reliability and operational performance.

For further discussion of nuclear issues, see Note 18 and Note 19 to the audited consolidated financial statements and Note 14 to the interim consolidated financial statements.

Electric Operating Statistics (Xcel Energy)

	Six months ended June 30,	Year ended December 31,		
	2003	2002	2001	2000
Electric sales (millions of Kwh):				
Residential	10,781	23,302	22,113	22,101
Commercial and industrial	27,964	57,815	57,755	57,409
Public authorities and other	558	1,143	1,103	1,184
Total retail	39,303	82,260	80,971	80,694
Sales for resale	11,030	23,256	26,104	26,284
Total energy sold	50,333	105,516	107,075	106,978
Number of customers at end of period:				
Residential	2,772,695	2,756,565	2,722,832	2,691,505
Commercial and industrial	399,699	394,620	387,579	380,784
Public authorities and other	81,409	81,341	100,819	98,715
Total retail	3,253,803	3,232,526	3,211,230	3,171,004
Wholesale	100	309	305	220
Total customers	3,253,903	3,232,835	3,211,535	3,171,224
Electric revenues (thousands of dollars):				
Residential	$ 814,940	$1,677,231	$1,697,390	$1,607,655
Commercial and industrial	1,440,390	2,791,550	2,979,730	2,772,550
Public authorities and other	52,203	98,394	91,438	94,653
Regulatory accrual adjustment		4,766	15,480	
Total retail	2,307,533	4,571,941	4,784,038	4,474,858
Wholesale	380,470	715,144	1,478,038	1,161,173
Other electric revenues	59,871	148,292	132,661	38,454
Total revenues	$2,747,874	$5,435,377	$6,394,737	$5,674,485

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Gas Utility Operations

Competition and Industry Restructuring

In the early 1990 s, the FERC issued Order No. 636, which mandated the unbundling of interstate natural gas pipeline services sales, transportation, storage and ancillary services. The implementation of Order No. 636 has resulted in additional competitive pressure on all local distribution companies (LDC) to keep gas supply and transmission prices for their large customers competitive. Customers have greater ability to buy gas directly from suppliers and arrange their own pipeline and LDC transportation service. Changes in regulatory policies and market forces have shifted the industry from traditional bundled gas sales service to an unbundled transportation and market based commodity service.

The natural gas delivery or transportation business has remained competitive as industrial and large commercial customers have the ability to bypass the local gas utility through the construction of interconnections directly with, and the purchase of gas directly from, interstate pipelines, thereby avoiding the delivery charges added by the local gas utility.

As LDCs, NSP-Minnesota, NSP-Wisconsin and PSCo provide unbundled transportation service to large customers. Transportation service does not have an adverse effect on earnings because the sales and transportation rates have been designed to make them economically indifferent to whether gas has been sold and transported or merely transported. However, some transportation customers may have greater opportunities or incentives to physically bypass the LDCs distribution system.

The Colorado Legislature passed legislation in 1999 that provides the CPUC the authority and responsibility to approve voluntary unbundling plans submitted by Colorado gas utilities in the future. PSCo has not filed a plan to further unbundle its gas service to all residential and commercial customers and continues to evaluate its business opportunities for doing so.

Capability and Demand

NSP-Minnesota and NSP-Wisconsin

We categorize our gas supply requirements as firm or interruptible (customers with an alternate energy supply). The maximum daily sendout (firm and interruptible) for the combined system of NSP-Minnesota and NSP-Wisconsin was 650,641 MMBtu for 2002, which occurred on January 2, 2002, and 727,354 MMBtu for the first six months of 2003, which occurred on January 20, 2003.

NSP-Minnesota and NSP-Wisconsin purchase gas from independent suppliers. The gas is delivered under gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 604,000 MMBtu/day. In addition, NSP-Minnesota and NSP-Wisconsin have contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 15 percent of winter season and 23 percent of peak daily, firm requirements of NSP-Minnesota and NSP-Wisconsin.

NSP-Minnesota and NSP-Wisconsin also own and operate two liquefied natural gas (LNG) plants with a storage capacity of 2.5 Billion cubic feet (Bcf) equivalent and four propane-air plants with a storage capacity of 1.4 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 32 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days and can be used to minimize daily imbalance fees on interstate pipelines.

NSP-Minnesota and NSP-Wisconsin are required to file for a change in gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or exchange one form of demand for another. In October 2001, the MPUC approved NSP s 2000-2001 entitlement levels, NSP-Minnesota s 2001-2002 entitlement levels were approved on April 3, 2002, which allow NSP-Minnesota to recover the demand entitlement costs associated with the increase in transportation and storage levels in its monthly PGA. NSP-Minnesota s filing for approval of its 2002-2003 entitlement levels is pending MPUC action.

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NSP-Wisconsin s winter 2002-2003 supply plan was approved by the PSCW in October 2002. NSP-Wisconsin s winter 2003-2004 supply plan is pending PSCW approval.

PSCo and Cheyenne

PSCo and Cheyenne project peak day gas supply requirements for firm sales and backup transportation (transportation customers contracting for firm supply backup) to be approximately 1,756,000 MMBtu. In addition, firm transportation customers hold 451,000 MMBtu of capacity without supply backup. Total firm delivery obligations for PSCo and Cheyenne are 2,206,870 MMBtu per day. The maximum daily deliveries for both companies for 2002 (firm and interruptible services) were 1,652,459 MMBtu, which occurred on February 25, 2002, and 1,652,938 MMBtu for the first six months of 2003, which occurred on February 24, 2003.

PSCo and Cheyenne purchase gas from independent suppliers. The gas supplies are delivered to the respective delivery systems through a combination of transportation agreements with interstate pipelines and deliveries by suppliers directly to each company. These agreements provide for firm deliverable pipeline capacity of approximately 1,220,000 MMBtu per day, which includes 797,000 MMBtu of supplies held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide about 38,000 MMBtu of gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at the companies city gate meter stations and a small amount received directly from wellhead sources.

PSCo has received approval to close one if its three storage facilities, Leyden Storage Field. The field s 110,000 MMBtu peak day capacity was replaced with additional third-party storage and transportation capacity.

PSCo is required by CPUC regulations to file a gas purchase plan by June of each year projecting and describing the quantities of gas supplies, upstream services and the costs of those supplies and services for the period beginning July 1 through June 30 of the following year. PSCo is also required to file a gas purchase report by October of each year reporting actual quantities and costs incurred for gas supplies and upstream services for the 12-month period ending the previous June 30.

Gas Supply and Costs

Our gas utilities actively seek gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. This diversification involves numerous domestic and Canadian supply sources, with varied contract lengths.

The following table summarizes the average cost per MMBtu of gas purchased for resale by our regulated retail gas distribution business:

	NSP-Minnesota	NSP-Wisconsin	PSCo	Cheyenne
First Six Months of 2003	$6.96	$6.46	$5.04	$4.40
2002	$3.98	$4.63	$3.17	$2.77
2001	$5.83	$5.11	$4.99	$5.03
2000	$4.56	$4.71	$4.48	$4.03

The cost of natural gas supply, transportation service and storage service is recovered through various cost recovery adjustment mechanisms.

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin have firm gas transportation contracts with several pipelines, which expire at various times from the remainder of 2003 through 2014. Approximately 80 percent of NSP-Minnesota and NSP-Wisconsin s retail gas customers are served from the Northern Natural Gas pipeline system.

NSP-Minnesota and NSP-Wisconsin have certain gas supply and transportation agreements that include obligations for the purchase and/or delivery of specified volumes of gas or to make payments in lieu of delivery. At June 30, 2003, NSP-Minnesota and NSP-Wisconsin were committed to approximately $792 million in such obligations under these contracts, which expire at various times from the remainder of 2003 through 2014.

NSP-Minnesota and NSP-Wisconsin purchase firm gas supply utilizing long-term and short-term agreements from approximately 37 domestic and Canadian suppliers under contracts. This diversity of suppliers and contract lengths allows NSP-Minnesota and NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

PSCo and Cheyenne

PSCo and Cheyenne have certain gas supply and transportation agreements that include obligations for the purchase and/or delivery of specified volumes of gas or to make payments in lieu of delivery. At June 30, 2003, PSCo and Cheyenne were committed to approximately $1.4 billion in such obligations under these contracts, which expire at various times from the remainder of 2003 through 2025.

PSCo and Cheyenne have attempted to maintain low-cost, reliable natural gas supplies by optimizing a balance of long-term and short-term gas purchases, firm transportation and gas storage contracts. PSCo and Cheyenne also utilize a mixture of fixed-price purchases and index-related purchases to provide a less volatile, yet market sensitive, price to their customers. During 2002 and the first six months of 2003, PSCo and Cheyenne purchased natural gas from approximately 48 suppliers.

Viking

On November 7, 2002, we reached an agreement to sell our former wholly owned subsidiary, Viking and Viking s share of Guardian Pipeline to Border Viking Company whose ultimate parent is Northern Border Partners L.P. The sale closed on January 17, 2003, and we received net proceeds of $124 million.

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Gas Operating Statistics (Xcel Energy)

	Six months ended June 30,	Year ended December 31,		
	2003	2002	2001	2000
Gas deliveries (thousands of Dth):				
Residential	83,198	144,038	136,568	137,989
Commercial and industrial	53,140	95,959	97,303	96,370
Total retail	136,338	239,997	233,871	234,359
Transportation and other	67,904	294,640	284,301	297,041
Total deliveries	204,242	534,637	518,172	531,400
Number of customers at end of period:				
Residential	1,583,573	1,574,489	1,531,589	1,483,114
Commercial and industrial	148,439	148,383	146,266	143,568
Total retail	1,732,012	1,722,872	1,677,855	1,626,682
Transportation and other	3,184	3,189	3,054	3,233
Total customers	1,735,196	1,726,061	1,680,909	1,629,915
Gas revenues (thousands of dollars):				
Residential	564,888	842,786	1,233,205	878,638
Commercial and industrial	336,600	455,152	711,282	506,040
Total retail	901,488	1,297,938	1,944,487	1,384,678
Transportation and other	38,197	99,862	108,164	84,202
Total revenues	939,685	1,397,800	2,052,651	1,468,880

Nonregulated Subsidiaries

Through our non-utility subsidiaries, we invest and operate several nonregulated businesses in a variety of industries. The following is an overview of the significant nonregulated businesses.

NRG Energy, Inc.

Voluntary Bankruptcy Petition NRG is a global energy company primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products.

At December 31, 2001, we indirectly owned approximately 74 percent of NRG. We owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering and 82 percent until a secondary offering was completed in March 2001.

In response to tightening credit standards experienced by NRG and the independent power production sector, on February 15, 2002 we announced a financial improvement and restructuring plan for NRG. The announced plan included an initial step of acquiring 100 percent ownership of NRG through a tender offer and merger to exchange all outstanding shares of NRG common stock with our common shares. In addition, the plan included:

financial support to NRG from us;

marketing certain NRG generating assets for possible sale;

canceling and deferring capital spending for NRG projects; and

combining certain NRG functions with our system and organization in order to realize greater synergies and to reduce expenses.

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In June 2002, we acquired 100 percent ownership of NRG through the acquisition of NRG minority common shares.

NRG had experienced significant growth in the past, especially the year 2001, expanding from 15,007 megawatts of net ownership interest in power generation facilities (including those under construction) as of December 31, 2000 to 24,357 megawatts of net ownership interests as of December 31, 2001. See a listing of NRG power generation facilities provided herein.

On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota. On February 19, 2003, NRG announced that it had reached a settlement with the petitioners. On May 12, 2003, the United States Bankruptcy Court for the District of Minnesota issued an order abstaining from exercising jurisdiction over any aspect of the case and dismissed the case.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the Support Agreement between us and NRG dated May 29, 2002. The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement are as follows:

We would pay up to $752 million to NRG to settle all claims of NRG against us, including all claims under the Support Agreement, and claims of NRG creditors who release us under the NRG plan of reorganization described below.

$350 million (including $112 million payable to NRG s bank lenders) would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made in early 2004.

$50 million also would be paid in early 2004, and all or any part of such payment could be made, at our election, in our common stock.

Up to $352 million would be paid commencing on April 30, 2004, unless at such time we had not received tax refunds equal to at least $352 million associated with the loss on our investment in NRG. To the extent such refunds are less than the required payments, the difference between the required payments and those refunds will be due on May 30, 2004.

$390 million of the up to $752 million of total payments are contingent on receiving releases from NRG creditors. To the extent we are not released by an NRG creditor, our obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon us receiving voluntary releases from at least 85 percent of the unsecured claims held by NRG creditors (including releases from 100 percent of NRG s bank creditors). As a result, it is not expected that our payment obligations would be reduced by more than approximately $60 million. Any reduction would come from our payments becoming due commencing on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guarantees or indemnities or other credit support obligations incurred by us for the benefit of NRG or any of NRG s subsidiaries would be terminated or other arrangements would be made such that we have no further liability and any cash collateral posted by us would be returned. As of October 31, 2003, no cash collateral was posted.

As part of the settlement with us, any intercompany claims we have against NRG or any subsidiary arising from the provision of goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of January 31, 2003, will be reduced to $10 million. The $10 million agreed amount is to be satisfied upon the effective date of the NRG plan of reorganization, 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.

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NRG and its subsidiaries would not be reconsolidated with us or any of our other affiliates for tax purposes at any time after their March 2001 deconsolidation (except to the extent required by state and local tax law) or treated as party to or otherwise entitled to the benefits of any existing tax sharing agreement with us. However, NRG and certain subsidiaries would continue to be treated as they were under our December 2000 tax allocation agreement to the extent they remain part of a consolidated or combined state tax group that includes us. Under the settlement, NRG would not be entitled to any tax benefits associated with the tax loss we expect to recognize as a result of the cancellation of our stock in NRG on the effective date of the NRG plan of reorganization.

Commencing on May 14, 2003, NRG and certain of NRG s affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement (based on the settlement discussed above) among us, NRG and NRG s major creditor constituencies that provides, among other things, for the payment by us of up to $752 million to NRG to settle all claims of NRG against us, including all claims under the Support Agreement. If the bankruptcy court approves the terms of the overall settlement, we will divest our ownership interest in NRG when NRG emerges from bankruptcy.

A plan support agreement reflecting the settlement has been signed by us, NRG, a holder of approximately 40 percent in principal amount of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. The terms of the plan support agreement with NRG s major creditors are basically the same as the March 26, 2003 tentative settlement discussed above. This agreement will become effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and specified other noteholders and bondholders and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. At this time, it appears unlikely that the plan support agreement will receive the requisite signatures prior to the effective date of the reorganization. However, it is expected that various settlement-related agreements incorporating the terms of the settlement, which will be exhibits or supplements to the plan of reorganization and would be subject to approval in connection with the confirmation of the plan of reorganization, would supercede the plan support agreement. If approved, these agreements would be expected to be executed when the plan of reorganization is confirmed.

Consummation of the overall settlement, including our obligations to make the payments set forth above, is contingent upon, among other things, the following:

The effective date of the NRG plan of reorganization for the NRG voluntary bankruptcy proceeding occurring on or prior to December 15, 2003;

The final plan of reorganization approved by the bankruptcy court and related documents containing terms satisfactory to us, NRG and various groups of the NRG creditors;

The receipt of releases in our favor from holders of at least 85 percent of the general unsecured claims held by NRG s creditors (including releases from 100 percent of NRG s bank creditors); and

Our receipt of all necessary regulatory and other approvals.

On July 22, 2003, we and NRG submitted a joint application to the FERC requesting approval for us to dispose of our interest in NRG by implementing the proposed plan of reorganization filed in the NRG bankruptcy proceeding. On October 8, 2003, the FERC issued an order approving the application.

On July 28, 2003, we and NRG submitted an application to the SEC under the Public Utility Holding Company Act of 1935 seeking authorization under the Act to perform those acts and consummate those transactions contemplated as part of NRG s proposed plan of reorganization. On October 10, 2003, the SEC issued an order approving the application.

On October 14, 2003, the solicitation for approval of NRG s plan of reorganization commenced. On November 12, 2003, votes on the plan of reorganization and objections to the plan of reorganization were due. Confirmation hearings on NRG s plan of reorganization have been scheduled for November 21, 2003 and

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November 24, 2003. Appeals to the NRG plan of reorganization must be filed within ten days after the confirmation of NRG s plan of reorganization.

Since many of these conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management believes at this time that the settlement will be implemented.

Based on the tax effect of an expected write-off of our investment in NRG, we have recognized at September 30, 2003, an estimate of $811 million of the expected tax benefits of the write-off, as discussed in Note 6 to the interim consolidated financial statements. Based on the expected timing of NRG s emergence from bankruptcy and the filing of 2003 tax returns and related carry-backs, as discussed in Note 4 to the interim consolidated financial statements, approximately $564 million of these deferred tax benefits have been classified as a current asset at September 30, 2003 to reflect refunds and estimated tax payment reductions expected in the 12 months after that date. In addition, the expected settlement payments of $752 million may generate additional tax benefits and be reflected once NRG s creditors approve the NRG plan of reorganization. Assuming all settlement payments are fully deductible, additional tax benefits of more than $260 million could be recorded at the time that such benefits are considered likely of realization based on a judgment as to when the settlement payments to NRG become probable for tax purposes.

We expect to claim a worthless stock deduction in 2003 on our investment in NRG. This would result in us having a net operating loss for the year for tax purposes. Under current law, this 2003 net operating loss could be carried back two years for federal tax purposes. We expect to file for a tax refund of approximately $325 million in first quarter 2004. This refund is based on a two-year carryback, as allowed under current tax law. As of June 30, 2003, our refund estimate was $355 million, which was based, in part, on an estimated 2002 tax liability that was recently determined to be lower than expected. The $30 million difference was refunded to us in October 2003.

As to the remaining $486 million of expected tax benefits, we expect to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The timing of cash savings from the reduction in estimated tax payments would depend on our taxable income.

NRG is organized into four regionally-based divisions: NRG North America, based in Minneapolis, Minnesota; NRG Europe, based in London, England; NRG Asia-Pacific, based in Brisbane, Australia; and NRG Latin America, based in Miami, Florida. Most of NRG s North American projects are grouped under regional holding companies corresponding to their domestic core market. NRG operates its United States generation facilities within each region as a separate operating unit within its power generation business. This regional portfolio structure allows NRG to coordinate the operations of its assets to take advantage of regional opportunities, reduce risks related to outages, whether planned or unplanned, and pursue expansion plans on a regional basis.

NRG s international power generation projects are managed as three distinct markets: Asia-Pacific, Europe and Other Americas.

NRG Divestitures and Project Terminations

At December 31, 2002, NRG had interests in power generation facilities with a total generating capacity of 46,346 megawatts. Of this amount, NRG had a net ownership of 28,770 megawatts. NRG also has interests in district heating and cooling systems and steam transmission operations. As of December 31, 2002, these thermal businesses had a steam and chilled water capacity equivalent to approximately 1,641 megawatts, of which NRG s net ownership interest is 1,514 megawatts.

Through January 31, 2003, NRG completed a number of transactions, which resulted in net cash proceeds to NRG after debt pay downs and after financial advisor fees of approximately $350 million. Subsequent to January 31, 2003, NRG has continued to attempt to generate cash by disposing of various interests.

In the second quarter of 2002, NRG announced the sale of its ownership interest in an Australian energy company, Energy Development Limited and its 50 percent interest in Collinsville Power Station in Australia. These transactions reached financial close during the third quarter of 2002 and the company received proceeds of approximately $45 million in exchange for its ownership interest in these two assets.

In the third quarter of 2002, NRG announced the sale of its Csepel power generating facilities, its 44.5 percent interest in the ECKG power station and its interest in Entrade, an electricity trading business. These transactions reached financial close in the fourth quarter 2002 and the first quarter of 2003 and the company realized net cash proceeds of approximately $200 million.

In the fourth quarter of 2002, NRG closed several transactions resulting in net proceeds of approximately $105 Million. The transactions included the sale of 60 percent interest in Compania Electrica Central Bulo Bulo S.A., a Bolivian corporation; NRG s transfer of its indirect 50 percent interest in SRW Cogeneration LP, which owns a cogeneration facility in Orange County, Texas; and NRG s sale of its 57.7 percent interest in the Crockett Cogeneration Project and the sale of its 39.5 percent indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership, in California.

In the first and second quarters of 2003, NRG entered into an agreement to dispose its Killingholme project and has committed to a plan to sell is Hsin Yu project, which is expected to be completed later in 2003. See Note 3 to the interim consolidated financial statements for a description of accounting treatment of disposed projects under SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets.

Connecticut Light & Power On December 5, 2001, NRG and Connecticut Light and Power (CL&P) filed a request with the Connecticut Department of Public Utility Control (DPUC) for an increase in the standard offer rate paid to energy suppliers. The increase was requested to cover higher costs related to recent environmental legislation and anticipated higher charges for transmission service. The increase would have contributed approximately $5 million of net income per month to NRG. On June 17, 2002, the DPUC ruled the parties were not entitled to the requested increase.

In July 2002, NRG reached a tentative agreement with CL&P that would result in increased compensation to NRG, as supplier of CL&P s wholesale supply agreement. As part of the agreement, NRG has committed to keeping power generation units in service at its Devon and Norwalk Harbor generating stations as well as at its Cos Cob remote jet sites for the remainder of the wholesale supply agreement. CL&P filed an emergency petition with the DPUC asking for approval of a shift of wholesale supply agreement revenues, effective August 1, 2002, through December 31, 2003, that would reallocate 0.7 cents per kilowatt-hour in the wholesale price paid to existing suppliers. On July 26, 2002, the DPUC denied the request of CL&P for an emergency letter ruling. NRG expects to continue negotiations for receipt of capacity payments for critical generating units in Connecticut.

On August 9, 2002, NRG announced it had finalized an agreement with ISO-New England to keep three units at its Devon station in service. Under the terms of the agreement, units seven and eight will remain available until ISO-New England gives a 60-day notice that one or both are no longer needed for reliability. Unit 10 may be deactivated on or after October 1, 2002. The agreement expires on September 30, 2003. The agreement provides for increased capacity payments and notice of termination. It also allows NRG sufficient compensation to continue operating through the end of the agreement.

Conectiv In April 2002, NRG terminated its purchase agreement with a subsidiary of Conectiv to acquire 794 megawatts of generating capacity and other assets, including an additional 66 megawatts of the Conemaugh Generating Station and an additional 42 megawatts of the Keystone Generating Station. Canceling the acquisition will result in a $230 million reduction in NRG s capital spending for 2002. No incremental costs were incurred by NRG related to the termination of this agreement.

FirstEnergy Assets In 2001, NRG had signed purchase agreements to acquire or lease a portfolio of generating assets from FirstEnergy Corporation. Under the terms of the agreements, NRG had agreed to finance approximately $1.6 billion for four primarily coal-fueled generating stations.

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On July 2, 2002, the FERC issued an order approving the transfer of FirstEnergy generating assets to NRG; however, the FERC conditioned the approval on NRG s assumption of FirstEnergy s obligations under a separate agreement between FirstEnergy and the City of Cleveland. These conditions required FirstEnergy to protect the City of Cleveland in the event the generating assets are taken out of service. On July 16, 2002, FERC clarified that the condition would require NRG to provide notice to the City of Cleveland and FirstEnergy if the generating assets were taken out of service and that other obligations remain with FirstEnergy.

On August 8, 2002, FirstEnergy and other parties under the purchase agreements related to FirstEnergy generating assets (collectively, the sellers) notified NRG that the purchase agreements had been cancelled. The sellers cited the reason for canceling the agreements as an alleged anticipatory breach of certain obligations in the agreements by NRG. The sellers also notified NRG that they were reserving the right to pursue legal action against NRG and us for damages, based on the alleged anticipatory breach. On February 5, 2003, the sellers submitted filings with the U.S. Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On February 27, 2003, the sellers gave NRG notice that they were commencing arbitration against NRG to determine whether NRG is liable to the sellers for failure to close the transaction. The parties selected the arbitration panel and also obtained relief from stay respecting NRG s present Chapter 11 Bankruptcy, although the collection of any award will remain fully subject to NRG s automatic stay. The parties have now reached an agreement in principle, which, if consummated and approved by regulators and the bankruptcy court, would liquidate the seller s bankruptcy claim at $396 million.

LSP Pike Energy, LLC In August 2002, The Shaw Group (Shaw) and NRG tentatively entered into an agreement to transfer NRG s interest in the assets in LSP Pike Energy, LLC (Pike), a 1,200-megawatt combined cycle gas turbine plant currently under construction in Mississippi, which is approximately one-third completed. The agreement was subject to approval by the NRG board of directors and lenders. To date, Pike, NRG and its lenders have not approved the agreement and are not expected to in the near future.

On October 17, 2002 Shaw filed an involuntary petition for liquidation of Pike under Chapter 7 of the U.S. Bankruptcy Code. Shaw also filed suit against us and NRG. The suit seeks recovery of approximately $130 million as a result of multiple breaches of contract. The parties have reached a settlement, which settlement is subject to approval by the bankruptcy court in the NRG bankruptcy. The carrying value of Pike s assets has been reduced to zero as a result of the impairments reflected as Special Charges. See discussion in Note 2 to the audited consolidated financial statements. See also Note 3 to the audited consolidated financial statements and Note 3 to the interim consolidated financial statements for discussion of other NRG divestitures that are reported as discontinued operations or assets held for sale as of September 30, 2003.

NRG Acquisitions in 2001

During 2001, NRG completed numerous acquisitions. NRG has generally financed the acquisition and development of projects under financing arrangements to be repaid solely from each of its project s cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. These acquisitions were recorded using the purchase method of accounting. Accordingly, the purchase prices were allocated to assets acquired and liabilities assumed based on their estimated fair values at the date of acquisition. Operations of the acquired companies have been included in the operations of NRG since the date of the respective acquisitions.

In January 2001, NRG purchased from LS Power, LLC a 5,339 MW portfolio of operating projects and projects in construction and advanced development that are located primarily in the north central and south central United States. Each facility employs natural gas-fired, combined-cycle technology. Through December 31, 2005, NRG also has the opportunity to acquire ownership interests in an additional 3,000 MW of generation projects developed and offered for sale by LS Power and its partners.

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In March 2001, NRG purchased from Cogentrix the remaining 430 MW, or 51.37 percent interest, in an 837 MW natural gas-fired combined-cycle plant in Batesville, Mississippi. NRG acquired a 48.63 percent interest in the plant in January 2001 from LS Power.

In June 2001, NRG purchased a 640 MW natural gas-fired power plant in Audrain County, Missouri from Duke Energy North America LLC.

In June 2001, NRG closed on the construction financing for the Brazos Valley generating facility, a 633 MW gas-fired power plant in Fort Bend County, Texas that NRG will build, operate and manage. At the time of the closing, NRG also became the 100 percent owner of the project by purchasing STEAG Power LLC s 50 percent interest in the project. During January 2003, NRG transferred its interest in the Brazos Valley project to its creditors.

In June 2001, NRG purchased 1,081 MW of interests in power generation plants from a subsidiary of Conectiv. NRG acquired a 100 percent interest in the 784 MW coal-fired Indian River Generating Station located near Millsboro, Delaware, and in the 170 MW oil-fired Vienna Generating Station located in Vienna, Maryland. In addition, NRG acquired 64 MW of the 1,711 MW coal-fired Conemaugh Generating Station located approximately 60 miles east of Pittsburgh, Pennsylvania and 63 MW of the 1,711 MW coal-fired Keystone Generating Station located approximately 50 miles east of Pittsburgh, Pennsylvania.

In June 2001, NRG purchased a 389 MW gas-fired power plant and a 116 MW thermal power plant, both of which are located on Csepel Island in Budapest, Hungary, from PowerGen. In April 2001, NRG also purchased from PowerGen its interest in Saale Energie GmbH and its 33.3 percent interest in MIBRAG BV. By acquiring PowerGen s interest in Saale Energie, NRG increased its ownership interest in the 960 MW coal-fired Schkopau power station located near Halle, Germany from 200 MW to 400 MW.

By acquiring PowerGen s interest in MIBRAG, an integrated energy business in eastern Germany consisting primarily of two lignite mines and three power stations, and following MIBRAG s buy back of the shares NRG acquired from PowerGen, NRG increased its ownership of MIBRAG from 33.3 percent to 50 percent. The Washington Group International, Inc., owns the remaining 50 percent of MIBRAG.

In August 2001, NRG acquired from Indeck Energy Services, Inc. an approximately 2,255 MW portfolio of operating projects and projects in advanced development, that are located in Illinois and upstate New York.

In August 2001, NRG acquired Duke Energy s 77 percent interest in the approximately 520 MW natural-gas fired McClain Energy Generating Facility located near Oklahoma City, Oklahoma. The Oklahoma Municipal Power Authority owns the remaining 23 percent interest. The McClain facility commenced operations in June 2001.

In September 2001, NRG acquired a 50 percent interest in TermoRio SA, a 1,040 MW gas-fired cogeneration facility currently under construction in Rio de Janeiro State, Brazil, from Petroleos Brasileiros SA (Petrobras). Commercial operation of the facility is expected to begin in March 2004. NRG has the option to put its interest in the project back to Petrobras after March 2002 if by that time certain milestones have not been met, including final agreement on the terms of all project documents.

During fiscal year 2001, NRG also acquired other minor interests in projects in Taiwan, India, Peru and the State of Nevada.

The respective purchase prices have been allocated to the net assets of the acquired entities as follows:

	Year ended December 31, 2001
Current assets	$ 307,654
Property plant and equipment	4,173,509
Non-current portion of notes receivable	736,041
Current portion of long term debt assumed	(61,268)
Other current liabilities	(99,666)
Long term debt assumed	(1,586,501)
Deferred income taxes	(149,988)
Other long term liabilities	(202,411)
Other non-current assets and liabilities	(181,473)
Total purchase price	2,935,897
Less Cash balances acquired (excluding restricted cash)	(122,780)
Net purchase price	$ 2,813,117

In July 2001, NRG signed agreements to acquire from Edison Mission Energy a 50 percent interest in the 375 MW Commonwealth Atlantic gas and oil-fired generating station located near Chesapeake, Virginia, and a 50 percent interest in the 110 MW James River coal-fired generating facility in Hopewell, Virginia. NRG closed the acquisition of the Commonwealth Atlantic and James River generating facilities in January 2002, for $11.2 million and $6.5 million, respectively.

e prime, Inc.

e prime was incorporated in 1995 under the laws of Colorado. e prime provides energy related products and services, which include natural gas marketing and trading and energy consulting. In 1996, e prime received authorization from the FERC to act as a power marketer. Additionally, e prime owns Young Gas Storage Company, which owns a 47.5 percent general partnership interest in an underground gas storage facility in northeastern Colorado.

e prime s gas trading operations acquire assets and commodities and subsequently trade around those assets or commodity positions. e prime captures trading opportunities through price volatility driven by factors such as asset utilization, locational price differentials, weather, available supplies, credit, and customer actions. Trading margins are captured through the utilization of transmission, transportation, and storage assets, capitalization on regional price differences, and other factors.

Other Subsidiaries

Although not individually reportable segments, we also have a number of nonregulated subsidiaries in various lines of business. The most significant are discussed below.

Xcel Energy International

XEI was formed in 1997 to manage our international operations, outside of NRG. At September 30, 2003, XEI s primary investment was Xcel Energy Argentina.

In April 1997, XEI purchased a 50 percent interest in Yorkshire Power, a U.K. regional electricity company, for approximately $362 million. Yorkshire Electricity s main business is the supply and distribution and supply of electricity and the supply of gas to approximately 2 million customers. During April 2001, XEI sold the majority of its investment in Yorkshire Power to Innogy Holdings plc. We received approximately $366 million for the sale, which approximated the book value of our investment.

As of September 30, 2003, XEI s investment in Argentina was $121 million. In December 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of XEI s investment. An impairment write-down of approximately $13 million, or 3 cents per share, was recorded in the fourth quarter of 2002. In the second quarter of 2003, XEI recorded a gain from a debt restructuring for one of its energy projects in Argentina, which increased earnings by 1 cent per share.

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

Utility Engineering

UE was incorporated in 1985 under the laws of Texas. UE is engaged in engineering, design, construction management and other miscellaneous services. UE currently has five wholly-owned subsidiaries Universal Utility Services LLC, Precision Resource Co., Quixx, Proto-Power and Applied Power Associates Inc. Universal Utility Services Co. provides cooling tower maintenance and repair, certain other industrial plant improvement services, and engineered maintenance of high-voltage plant electric equipment. Precision Resource Co. provides contract professional and technical resources for customers in the energy industrial sectors. Quixx was incorporated in 1985 under the laws of Texas. Quixx s primary business is investing in and developing cogeneration and energy-related projects. Quixx also holds water rights and certain other non-utility assets. Quixx financed the sale of heat pumps until December 1999.

Planergy International Inc.

Planergy was acquired in 1998. Planergy provides energy management, consulting, on-site generation, load curtailment, demand-side management, energy conservation and optimization, distributed generation and power quality services, as well as information management solutions to industrial, commercial and utility customers.

EMI began operations in 1993. EMI primarily offers retrofitting and upgrading facilities for greater energy efficiency on a national basis. In 1995, EMI acquired Energy Masters Corporation, a company that specializes in energy efficiency improvement services for commercial, industrial and institutional customers. In 1997, EMI acquired 100 percent of Energy Solutions International Inc., an energy management firm.

During 2000, Planergy and EMI, both wholly-owned subsidiaries of ours, were combined to form Planergy.

Seren Innovations, Inc.

Seren was formed in 1996 to pursue communications and data services businesses. Currently, Seren is constructing a combination cable television, telephone and high-speed internet access system in two locations: St. Cloud, Minnesota and Contra Costa County in the East Bay area of northern California. As of September 30, 2003, our investment in Seren was approximately $266 million. Seren projects improvement in its operating results with positive cash flow anticipated in 2005 and earnings contribution in 2008.

Eloigne Company

Eloigne was established in 1993 and its principal business is the acquisition of rental housing projects that qualify for low-income housing tax credits under current federal tax law. As of December 31, 2002, approximately $83 million had been invested in Eloigne projects, including approximately $23 million in wholly owned properties and approximately $60 million in equity interests in jointly owned projects. As of

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September 30, 2003, approximately $74 million had been invested in Eloigne projects, including approximately $22 million in wholly owned properties and approximately $52 million in equity interests in jointly owned projects.

Completed and committed Eloigne projects as of September 30, 2003 are expected to generate tax credits of $67 million over the time period of 2003 through 2011.

Environmental Matters

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

We and our subsidiaries strive to comply with all environmental regulations applicable to its operations. However, it is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, generally, what effect future laws or regulations may have upon our operations. For more information on Environmental Contingencies, see Note 18 and Note 19 to the audited consolidated financial statements, Note 8 to the interim consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operation Factors Affecting Results of Operations Environmental Matters.

Capital Spending and Financing

For a discussion of expected capital expenditures and funding sources, see Management s Discussion and Analysis of Financial Condition and Results of Operation.

Properties

For a discussion and information concerning nonregulated properties, see Nonregulated Subsidiaries above.

Virtually all of the utility plant of NSP-Minnesota, NSP-Wisconsin and PSCo is subject to the lien of their first mortgage bond indentures.

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Electric Utility Generating Stations

Listed below are our utility subsidiaries interest in electricity utility generating stations as of December 31, 2002.

NSP-Minnesota

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Sherburne Becker, Minnesota			
Unit 1	Coal	1976	706
Unit 2	Coal	1977	689
Unit 3(a)	Coal	1987	507
Prairie Island Welch, Minnesota			
Unit 1	Nuclear	1973	522
Unit 2	Nuclear	1974	522
Monticello Monticello, Minnesota	Nuclear	1971	578
King Bayport, Minnesota	Coal	1968	529
Black Dog Burnsville, Minnesota			
2 Units	Coal	1955-1960	278
2 Units	Natural Gas	2002	260
High Bridge St. Paul, Minnesota			
2 Units	Coal	1956-1959	267
Riverside Minneapolis, Minnesota			
2 Units	Coal	1964-1987	374
Angus Anson-Sioux Falls, S.D			
2 Units	Natural Gas	1994	217
Inver Hills-Inver Grive Heights, Minn			
6 Units	Natural Gas	1972	306
Blue Lake-Shakopee, Minn			
4 Units	Natural Gas	1974	160
Other	Various	Various	323
		Total	6,238

(a) Based on NSP-Minnesota s ownership interest of 59 percent.

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NSP-Wisconsin

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Combustion Turbine:			
Flambeau Station Park Falls, Wisconsin	Natural Gas/Oil	1969	12
Wheaton Eau Claire, Wisconsin			
6 Units	Natural Gas/Oil	1973	345
French Island La Crosse, Wisconsin			
2 Units	Oil	1974	142
Steam:			
Bay Front Ashland, Wisconsin			
3 Units	Coal/Wood/ Natural Gas	1945-1960	76
French Island La Crosse, Wisconsin			
2 Units	Wood/RDF*	1940-1948	27
Hydro:			
19 Plants		Various	249
		Total	851

* RDF is refuse derived fuel, made from municipal solid waste.

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PSCo

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Steam:			
Arapahoe Denver, Colorado			
2 Units	Coal	1950-1955	156
Cameo Grand Junction, Colorado			
2 Units	Coal	1957-1960	73
Cherokee Denver, Colorado			
4 Units	Coal	1957-1968	717
Comanche Pueblo, Colorado			
2 Units	Coal	1973-1975	660
Craig Craig, Colorado			
2 Units(a)	Coal	1979-1980(a)	83
Hayden Hayden, Colorado			
2 Units(b)	Coal	1965-1976(b)	237
Pawnee Brush, Colorado	Coal	1981	505
Valmont Boulder, Colorado	Coal	1964	186
Zuni Denver, Colorado			
3 Units	Natural Gas/Oil	1948-1954	107
Combustion Turbines:			
Fort St. Vrain Platteville, Colorado 4 Units	Natural Gas	1972-2001	690
Various Locations			
6 Units	Natural Gas	Various	171
Hydro:			
Various Locations			
14 Units		Various	32
Cabin Creek Georgetown, Colorado		1967	210
Pumped Storage Wind:			
Ponnequin Weld County, Colorado		1999-2001	
Diesel Generators:			
Cherokee Denver, Colorado			
2 Units		1967	6
		Total	3,833

(a) Based on PSCo ownership interest of 9.72 percent

(b) Based on PSCo ownership interest of 75.5 percent of unit 1 and 37.4 percent of unit 2.

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SPS

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Steam:			
Harrington Amarillo, Texas			
3 Units	Coal	1976-1980	1,066
Tolk Muleshoe, Texas			
2 Units	Coal	1982-1985	1,080
Jones Lubbock, Texas			
2 Units	Natural Gas	1971-1974	486
Plant X Earth, Texas			
4 Units	Natural Gas	1952-1964	442
Nichols Amarillo, Texas			
3 Units	Natural Gas	1960-1968	457
Cunningham Hobbs, New Mexico			
2 Units	Natural Gas	1957-1965	267
Maddox Hobbs, New Mexico.	Natural Gas	1983	118
CZ-2 Pampa, Texas	Purchased Steam	1979	26
Moore County Amarillo, Texas	Natural Gas	1954	48
Gas Turbine:			
Carlsbad Carlsbad, Texas	Natural Gas	1977	13
CZ-1 Pampa, Texas	Hot Nitrogen	1965	13
Maddox Hobbs, New Mexico.	Natural Gas	1983	65
Riverview Electric City, Texas	Natural Gas	1973	23
Cunningham Hobbs, New Mexico.	Natural Gas	1998	220
Diesel:			
Tucumcari Tucumcari, New Mexico			
6 Units		1941-1968	
		Total	4,324

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at June 30, 2003:

Conductor Miles	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 kilovolt (kv)		2,919			
345 kv		5,653	1,312	538	2,735
230 kv		1,440		10,264	9,224
161 kv		298	1,331		
138 kv				92	
115 kv	113	6,162	1,528	5,033	10,825
Less than 115 kv	3,199	78,518	31,092	68,339	21,485

Electric utility transmission and distribution substations at June 30, 2003:

	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity of substations	5	361	205	210	492

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Gas utility mains at June 30, 2003:

Miles	BMG	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission			115		2,279	12
Distribution	415	677	8,707	1,957	18,283	

Independent Power Production and Cogeneration Facilities

Listed below are descriptions of NRG s interests in independent power production and cogeneration facilities as of June 30, 2003.

Name and Location of Facility	Purchaser/Power Market	Net Owned Capacity (megawatts)	NRG s Percentage Ownership Interest	Fuel Type
East Region:				
Oswego, New York	Niagara Mohawk/ NYISO	1,700	100%	Oil/Gas
Huntley, New York	Niagara Mohawk/ NYISO	760	100%	Coal
Dunkirk, New York	Niagara Mohawk/ NYISO	600	100%	Coal
Arthur Kill, New York	NYISO	842	100%	Gas/Oil
Berrians, New York	NYISO	79	100%	Gas/Oil
Astoria Gas Turbines, New York	NYISO	614	100%	Gas/Oil
Ilion, New York	NYISO	60	100%	Gas/Oil
Somerset, Massachusetts	Eastern Utilities Associates	229	100%	Coal/Oil/Jet
Middletown, Connecticut	Connecticut Light & Power	856	100%	Oil/Gas/Jet
Montville, Connecticut	Connecticut Light & Power	498	100%	Oil/Gas
Devon, Connecticut	Connecticut Light & Power	401	100%	Gas/Oil/Jet
Norwalk Harbor	Connecticut Light & Power	353	100%	Oil
Connecticut Jet Power, Connecticut	Connecticut Light & Power	127	100%	Jet
Other 6 Projects	Various	68	Various	Various
Indian River, Delaware	Delmarva/PJM	784	100%	Coal/Oil
Dover, Delaware	PJM	106	100%	Gas/Coal
Vienna, Maryland	Delmarva/PJM	170	100%	Oil
Conemaugh, Pennsylvania	PJM	64	3.72%	Coal/Oil
Keystone, Pennsylvania	PJM	63	3.70%	Coal/Oil
Paxton Creek Cogeneration, Pennsylvania	Virginia Electric & Power	12	100%	Gas
Commonwealth Atlantic	PJM	188	50%	Coal/Oil
James River	PJM	55	50%	Coal/Oil

Name and Location of Facility	Purchaser/Power Market	Net Owned Capacity (megawatts)	NRG s Percentage Ownership Interest	Fuel Type
Central Region:				
Big Cajun II, Louisiana	Cooperative/SERC Entergy	1,498	86.04%	Coal
Big Cajun I, Louisiana	Cooperative/SERC Entergy	458	100%	Gas
Bayou Cove, Louisiana	SERC Entergy	320	100%	Gas
Sterlington, Louisiana	Louisiana Generating	202	100%	Gas
Batesville, Mississippi	SERC-TVA	837	100%	Gas
McClain, Oklahoma	SPP-Southern	400	77%	Gas
Mustang, Texas	Golden Spread Electric	122	25%	Gas Coop
Other 3 Projects	Various	45	Various	Various
Kendall, Illinois	MAIN	1,168	100%	Gas
Rockford I, Illinois	ComEd	342	100%	Gas
Rockford II, Illinois	MAIN	171	100%	Gas
Rocky Road Power, Illinois	MAIN	175	50%	Gas
Audrain, Missouri	MAIN/SERC Entergy	640	100%	Gas
Other 2 projects	Various	42	Various	Various
West Coast Region:				
El Segundo Power, California	California DWR	510	50%	Gas
Encina, California	California DWR	483	50%	Gas/Oil
Long Beach Generating, California	California DWR	265	50%	Gas
San Diego Combustion Turbines, California	Cal ISO	127	50%	Gas/Oil
Saguaro Power Co., Nevada	Nevada Power	53	50%	Gas/Oil
Other North America:				
NEO Corporation, Various	Various	197	71.49%	Various
Energy Investors Funds, Various	Various	13	0.73%	Various
International Projects:				
Asia-Pacific:				
Hsinchu, Taiwan	Industrials	102	60%	Gas
Australia:				
Flinders, South Australia	South Australian Pool	760	100%	Coal
Gladstone Power Station, Queensland	Enertrade/ Boyne Smelters	630	37.50%	Coal
Loy Yang Power A, Victoria	Victorian Pool	507	25.37%	Coal
Europe:				
Enfield Energy Centre, UK	UK Electricity Grid	99	25%	Gas/Oil
Schkopau Power Station, Germany	VEAG/Industrials	400	41.67%	Coal
MIBRAG mbH, Germany	ENVIA/ MIBRAG Mines	119	50%	Coal
CEEP Fund, Poland	Industrials	5	7.56%	Gas/Coal

Name and Location of Facility	Purchaser/Power Market	Net Owned Capacity (megawatts)	NRG s Percentage Ownership Interest	Fuel Type
Other Americas:				
TermoRio, Brazil	Petrobras	520	50%	Gas/Oil
Itiquira Energetica, Brazil	COPEL/ Tradener	154	93.3%	Hydro
COBEE, Bolivia	Electropaz/ELF	217	100%	Hydro/Gas
Energia Pacasmayo, Peru	Electroperu/ Peruvian Grid	66	100%	Hydro/Oil
Cahua, Peru	Quimpac/ Industrials	45	100%	Hydro
Latin Power, Various	Various	52	6.75%	Various

Thermal Energy Production and Transmission Facilities and Resource Recovery Facilities

Listed below are NRG s interests in thermal energy production and transmission facilities and resource recovery facilities as of June 30, 2003.

Name and Location of Facility	Date of Acquisition	Net Owned Capacity(1)	NRG s Percentage Ownership Interest	Thermal Energy Purchaser/ MSW Supplier
NRG Energy Center	1993	Steam: 1,403 mmBtu/hr. (411 MWt)	100%	Approximately 100 steam customers
Minneapolis, Minnesota		Chilled water: 42,450 tons (149 MWt)		40 chilled water customers
NRG Energy Center	1999	Steam: 490 mmBtu/hr.	100%	Approximately 185 steam customers
San Francisco, California		(144 MWt)		
NRG Energy Center	2000	Steam: 490 mmBtu/hr. (144 MWt)	100%	Approximately 295 steam customers
Harrisburg, Pennsylvania		Chilled water: 1,800 tons (6 MWt)		and 2 chilled water customers
NRG Energy Center	1999	Steam: 260 mmBtu/hr. (76 MWt)	100%	Approximately 30 steam and 30
Pittsburgh, Pennsylvania		Chilled water: 12,580 tons (44 MWt)		chilled water customers
NRG Energy Center	1997	Chilled water: 8,000 tons (28 MWt)	100%	Approximately 20 chilled water
San Diego, California				customers
NRG Energy Center	1992	Steam: 430 mmBtu/hr. (126 Mwt)	100%	Rock-Tenn Company
Rock-Tenn, Minnesota				
Camas Power Boiler,	1997	Steam: 200 mmBtu/hr. (59 MWt)	100%	Georgia-Pacific Corp.
Washington				
NRG Energy Center	2000	Steam: 190 mmBtu/hr. (56 MWt)	100%	Kraft Foods Inc
Dover, Delaware				
NRG Energy Center	1992	Steam: 160 mmBtu/hr. (47 MWt)	100%	Anderson Corporation, Minnesota
Washco, Minnesota				Correctional Facility
+Resource Recovery Facilities	1993	MSW 1,500 tons/day	100%	Ramsey and Washington Counties
Newport, Minnesota				
Elk River, Minnesota	2001	MSW: 1,275 tons/day	85%	Anoka, Hennepin, and Sherburne Counties; Tri-County Solid Waste

				Management Commission
Penobscot Energy Recovery, Maine	1997	MSW: 590 tons/day	85%	Bangor Hydroelectric Company

(1) Thermal production and transmission capacity is based on 1,000 Btu s per pound of steam production or transmission capacity. The unit mmbtu is equal to one million Btu s.

In addition, NRG leases its corporate offices at 901 Marquette, Suite 2300, Minneapolis, Minnesota and various other office spaces.

Employees

The number of our employees at June 30, 2003, is presented in the table below. Of the employees listed below, 7,177, or 51.7 percent, are covered under collective bargaining agreements.

NSP-Minnesota	2,930
NSP-Wisconsin	542
PSCo.	2,405
SPS	988
Xcel Energy Services Inc.	2,908
NRG	3,111
Other subsidiaries	1,035
Total	13,919

Legal Proceedings

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

Department of Energy Complaint On June 8, 1998, NSP-Minnesota filed a complaint in the Court of Federal Claims against the DOE requesting damages in excess of $1 billion for the DOE s partial breach of the Standard Contract. NSP-Minnesota requested damages consisting of the costs of storage of spent nuclear fuel at the Prairie Island nuclear generating plant, anticipated costs related to the Private Fuel Storage, LLC and costs relating to the 1994 state legislation limiting the number of casks that can be used to store spent nuclear fuel at Prairie Island. On April 6, 1999, the Court of Federal Claims dismissed NSP-Minnesota s complaint. On May 20, 1999, NSP-Minnesota appealed to the Court of Appeals for the Federal Circuit. On August 31, 2000, the Court of Appeals for the Federal Circuit reversed and remanded to the Court of Federal Claims. On December 26, 2000, NSP-Minnesota filed a motion with the Court of Federal Claims to amend its complaint and renew its motion for summary judgment on the DOE s liability. On July 31, 2001, the Court of Federal Claims granted NSP s motion for summary judgment on DOE s liability. On November 28, 2001, the DOE brought a motion of partial summary judgment on the schedule for acceptance of spent nuclear fuel and on November 27, 2001 the DOE s obligation to accept greater than Class C waste. These motions are pending. Limited discovery with respect to the schedule to the schedule issues has been conducted. The Court of Federal Claims has selected four lead cases to proceed to trial. The suit brought by NSP-Minnesota was not selected as a lead case and has been stayed. A trial in NSP-Minnesota s suit against the DOE is not likely to occur before the third quarter of 2004.

Fortistar Litigation In July 1999, Fortistar Capital, Inc., a Delaware corporation, filed a complaint in District Court (Fourth Judicial District, Hennepin County) in Minnesota against NRG asserting claims for injunctive relief and for damages of over $50 million as a result of NRG s alleged breach of a confidentiality letter agreement with Fortistar relating to the Oswego facility in New York. NRG disputed Fortistar s allegations and asserted numerous counterclaims. In October 1999, NRG, through a wholly owned subsidiary, closed on the acquisition of the Oswego facility. In April and December 2000, NRG filed summary judgment motions to dispose of the litigation. A hearing on these motions was held in February 2001 and certain of Fortistar s claims were dismissed. The parties resolved the litigation in May 2002 and entered into a conditional, confidential settlement agreement that was subject to necessary board and lender approvals. NRG was unable to obtain necessary approvals. Fortistar has moved the court to enforce the settlement, seeking damages in excess of $35 million plus interest and attorneys fees. NRG is opposing Fortistar s motion on the grounds that conditions to contract performance have not been satisfied. No decision has been made on the pending motion, and NRG cannot predict the outcome of this dispute. On June 3, 2003, Fortistar filed a motion with the Bankruptcy Court seeking relief from the automatic stay of 11 U.S.C. §362 to proceed with the pending Minnesota state court litigation. NRG filed an objection to the request for relief from stay and the

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Bankruptcy denied Fortistar s request. NRG cannot predict the outcome of the underlying dispute between the parties that encompassed litigation with respect to the Oswego facility as well as litigation between the parties with respect to Minnesota Methane LLC.

Stray Voltage On September 25, 2000, NSP-Wisconsin was served with a complaint in Eau Claire County Circuit Court on behalf of Claron and Janice Stubrud. The complaint alleged that stray voltage from NSP-Wisconsin s system harmed their dairy herd resulting in lost milk production, lost profits and income, property damage and injury to their dairy herd. The complaint also alleged that NSP-Wisconsin acted willfully and wantonly, entitling plaintiffs to treble damages. The plaintiffs allege farm damages of approximately $3.8 million, $2.7 million of which represents prejudgment interest. On March 28, 2003, the trial court granted partial summary judgment to NSP-Wisconsin and dismissed plaintiffs claims for strict products liability, trespass, treble damages and prejudgment interest. The case was resolved in August 2003.

On November 13, 2001, Ralph Schmidt, Karline Schmidt, August C. Heeg Jr., and Joanne Heeg filed a complaint in Clark County, Wisconsin against Xcel Energy Services Inc. (XES), our wholly-owned subsidiary. The complaint alleged that stray voltage harmed their dairy herd resulting in decreased milk production, lost profits and income, property damage and injury to their dairy herd. The plaintiffs also allege entitlement to treble damages. The Heeg plaintiffs allege compensatory damages of $1.9 million and pre-verdict interest of $6.1 million, for total damages of $8 million. The Schmidt plaintiffs allege compensatory damages of $1 million and pre-verdict interest of $1.2 million, for total damages of $2.2 million. No trial date has been set. At all relevant times, NSP-Wisconsin provided utility service to plaintiffs; therefore XES is seeking dismissal of XES and substitution of NSP-Wisconsin as the proper party defendant.

On March 1, 2002, NSP-Wisconsin was served with a lawsuit commenced by James and Grace Gumz and Michael and Susan Gumz in Marathon County Circuit Court, Wisconsin, alleging that electricity supplied by NSP-Wisconsin harmed their dairy herd and caused them personal injury. The Gumz s complaint alleges negligence, strict liability, nuisance, trespass, and statutory violations and seeks compensatory, punitive and treble damages. Plaintiffs allege compensatory damages of $1.7 million and pre-verdict interest of $1.8 million for total damages of $3.5 million. Trial has been set for March 2004.

On July 28, 2003, James and Elaine Nigon, defendants in a real estate misrepresentation suit commenced in Clark County Circuit Court by Dennis and Kathy Weber, served NSP-Wisconsin with a third-party summons and complaint. The Webers purchased a dairy farm from the Nigons in June 2000, and allege that the Nigons misrepresented the existence of stray voltage problems at the farm. The Nigons have joined NSP-Wisconsin as a third-party defendant, alleging that if they are liable to plaintiffs, it is as a result of their reliance on NSP-Wisconsin s representations regarding stray voltage levels at the farm. NSP-Wisconsin is not aware of the amount of damages being claimed by the Webers. A final pretrial hearing has been set for May 7, 2004, at which time a trial date will be determined.

French Island NSP-Wisconsin s French Island plant generates electricity by burning a mixture of wood waste and refuse derived fuel. The fuel is derived from municipal solid waste furnished under a contract with La Crosse County, Wisconsin. In October 2000, the EPA reversed a prior decision and found that the plant was subject to the federal large combustor regulations. Those regulations became effective on December 19, 2000. NSP-Wisconsin did not have adequate time to install the emission controls necessary to come into compliance with the large combustor regulations by the compliance date. As a result, on March 29, 2001, the EPA issued a finding of violation to NSP-Wisconsin. On April 2, 2001, a conservation group sent NSP-Wisconsin a notice of intent to sue under the citizen suit provisions of the Clean Air Act. NSP-Wisconsin could be fined up to $27,500 per day for each violation. On October 20, 2003, the U.S. District Court in Madison, Wisconsin entered a consent decree settling the EPA s claims against NSP-Wisconsin related to the French Island generating plant, but denying any liability. The consent decree is now enforceable. On or before November 19, 2003, NSP-Wisconsin will pay a civil penalty of $500,000.

On August 15, 2001, NSP-Wisconsin received a Certificate of Authority to install control equipment necessary to bring the French Island plant into compliance with the large combustor regulations. NSP-Wisconsin began construction of the new air quality equipment on October 1, 2001. NSP-Wisconsin has reached an agreement in principle with La Crosse County through which La Crosse County will pay for the extra emissions equipment required to comply with the EPA regulation. Installation of the control equipment has been completed and source tests on one unit confirm that the unit is now in compliance with the state and federal dioxin standards.

On July 27, 2001, the State of Wisconsin filed a lawsuit against NSP-Wisconsin in the Wisconsin Circuit Court for La Crosse County, contending that NSP-Wisconsin exceeded dioxin emission limits on numerous occasions between July 1995 and December 2000 at French Island. On September 3, 2002, the Wisconsin Circuit Court approved a settlement between NSP-Wisconsin and the state of Wisconsin. Under terms of that settlement, NSP-Wisconsin paid a penalty of approximately $168,000 and agreed to contribute $300,000 in installments through 2005 to help fund a household hazardous waste project in the LaCrosse area.

Fort Collins Manufactured Gas Plant Site Prior to 1926, Poudre Valley Gas Company, a predecessor of PSCo, operated a manufactured gas plant in Fort Collins, Colorado near the Cache la Poudre River. In 1926, after acquiring the Poudre Valley Gas Company, PSCo shut down the gas site and, years later, sold most of the property. In the mid-1990s, contamination associated with coal tar left behind by the gas plant operations was discovered on the gas plant site, and PSCo paid for a portion of a partial cleanup. Recently, an oily substance similar to coal tar has been discovered in the Cache la Poudre River. The source of this substance has not yet been identified. PSCo is working with government agencies, 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. PSCo estimates that the cost of initial removal and investigation activities will be approximately $250,000. Sufficient information is not available at this time to estimate the ultimate liability, if any, for this site.

New York Department of Environmental Control Opacity Notice of Violation NRG became part of an opacity consent order as a result of acquiring the Niagara Mohawk assets. At the time of financial close, the consent order was being negotiated between Niagara Mohawk and the New York Department of Environmental Control (NYDEC). The consent order required Niagara Mohawk to pay a stipulated penalty for each opacity event. An opacity event is an event in time, usually six minutes or 20 minutes, when a plant s emissions do not meet minimum levels of air transparency. On January 14, 2002, the NYDEC issued NRG notices of violations (NOVs) for opacity events, which had occurred since the time NRG assumed ownership of the Huntley, Dunkirk and Oswego Generating Stations. The NOVs alleged that a total of 7,231 events had occurred where the average opacity during the six-minute block of time had exceeded 20 percent. The NYDEC currently proposes a penalty associated with the NOVs at $900,000. Subsequently, the NYDEC has indicated that a consent order, not yet received by NRG, will seek a penalty in excess of that previously proposed. NRG expects to continue negotiations with NYDEC regarding the proposed consent orders, but cannot predict the outcome of those negotiations.

Light Rail Transit (LRT) On February 16, 2001, NSP-Minnesota filed a suit in the United States District Court in Minneapolis against the Minnesota Metropolitan Council, Minnesota Department of Transportation, State of Minnesota and the Federal Transit Administration (FTA) to prevent pave-over of NSP-Minnesota s underground facilities during construction of the LRT system. NSP-Minnesota also is seeking recovery of relocation expenses. State defendants countersued, seeking delay damages and a $330 million surety bond. On May 24, 2001, the District Court issued a preliminary injunction requiring NSP-Minnesota to commence the relocation project and to cooperate with defendants. NSP-Minnesota has complied with the preliminary injunction and utility line relocation has commenced. NSP-Minnesota is capitalizing its costs incurred as construction work in progress. In April 2002, Defendants brought motions for summary judgment before the federal district court. In September, 2002 the District Court granted the defendants motion for summary judgment. NSP is preparing its appeal to the Federal Court of Appeals for the Eighth District. In collateral matters regarding LRT construction, NSP-Minnesota has commenced a mandamus action in state district court seeking an order requiring Defendants to commence condemnation proceedings concerning an underground substation, access to which is blocked by LRT. The state court denied the action for mandamus and NSP-Minnesota appealed to the Minnesota Court of Appeals. On August 19, 2003, the Minnesota Court of Appeals reversed and remanded and directed the district court to determine if access to the underground substation has been unreasonably denied.

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Connecticut Light & Power Company v. NRG Power Marketing Inc., Docket No. 3:01-CV-2373 (A WT), pending in the United States District Court, District of Connecticut This matter involves a claim by Connecticut Light & Power Company (CL&P) for recovery of amounts it claims are owing for congestion charges under the terms of a standard offer services contract between the parties, dated October 29, 1999. CL&P has served and filed its motion for summary judgment to which NRG Power Marketing Inc. (NRG PMI) filed a response on March 21, 2003. CL&P has offset approximately $30 million from amounts owed to NRG PMI, claiming that it has the right to offset those amounts under the contract. NRG PMI has counterclaimed seeking to recover those amounts, arguing among other things that CL&P has no rights under the contract to offset them. On May 14, 2003, NRG PMI provided notice to CL&P of termination of the contract effective May 19, 2003. Pursuant to the request of the Attorney General of Connecticut and the Connecticut Department of Public Utility Control, on May 16, 2003, the FERC issued an order directing NRG PMI to continue to provide service to CL&P under the contract, pending further order by the FERC. By reason of the bankruptcy stay, the court has not ruled on the pending motion. On May 19, 2003, NRG PMI withdrew its notice of termination of the contract. On June 25, 2003, the FERC issued an order directing NRG PMI to continue to provide service to CL&P under the contract, pending further notice by the FERC. NRG PMI cannot estimate at this time the likelihood of an unfavorable outcome in this matter, or the overall exposure for congestion charges for the full term of the contract. We have reflected in our share of NRG earnings any estimated loss reserves recorded by NRG for these legal contingencies as of NRG s bankruptcy filing date (May 14, 2003). Due to limitations on losses that we can record for NRG, as discussed in Note 5 to the interim consolidated financial statements, any changes in NRG s loss reserves by NRG after the bankruptcy date will not affect our results.

Connecticut Light & Power Related Proceedings at the Federal Energy Regulatory Commission, the United States District Court for the Southern District of New York, and the United States Court of Appeals for the D.C. Circuit and the Second Circuit In May 2003, when NRG PMI took steps to terminate or reject in bankruptcy the subject standard offer services contract with CL&P (the CL&P Contract), the Connecticut Attorney General and the Connecticut Department of Public Utility Control (DPUC) sought and obtained from the FERC its above-referenced May 16, 2003 order temporarily requiring NRG PMI to continue to comply with the terms of the CL&P Contract, pending further notice from the FERC. Thereafter, on June 2, 2003, the United States Bankruptcy Court for the Southern District of New York issued its order specifically authorizing NRG PMI s rejection of the CL&P Contract, and by order dated June 12, 2003, the United States District Court for the Southern District of New York granted NRG PMI s motion for a temporary restraining order staying all actions by CL&P, the Connecticut Attorney General and the DPUC to enforce or apply the above-referenced FERC order and affording NRG PMI leave to cease its performance under the CL&P Contract, effective retroactive to June 2, 2003. The FERC then issued an order on June 25, 2003, that again commanded NRG PMI s continued performance regardless of any contrary ruling by the bankruptcy court and the District Court s temporary restraining order. By order dated June 30, 2003, the District Court dismissed NRG PMI s motion for preliminary injunction for lack of subject matter jurisdiction. On July 1, 2003, NRG PMI resumed performance under the CL&P Contract. On August 15, 2003, the FERC entered two additional orders: one served to uphold the CL&P Contract and purported to require NRG PMI to perform thereunder, and the other denying NRG PMI s prior rehearing request. NRG PMI has appealed to the Second Circuit respecting the District Court s refusal to enjoin the FERC and maintain the restraining order. NRG awaits the Second Circuit s decision on the above appeal, as well as the permanent order by the FERC with respect to NRG PMI s continued performance under the CL&P Contract. Should NRG PMI have to perform for the duration of the CL&P Contract, this could have an adverse financial consequence approaching $100 million. Meanwhile, the parties continue to engage in settlement negotiations to all of the foregoing litigation. We have reflected in our share of NRG earnings any estimated loss reserves recorded by NRG for these legal contingencies as of NRG s bankruptcy filing date (May 14, 2003). Due to limitations on losses that we can record for NRG, as discussed in Note 5 to the interim consolidated financial statements, any changes in NRG s loss reserves by NRG after the bankruptcy date will not affect our results.

NRG Litigation In February 2002, individual stockholders of NRG filed nine separate, but similar, class action complaints in the Delaware Court of Chancery against us, NRG and the nine members of NRG s board of directors, all of which were consolidated for unified handling. A similar class action lawsuit was filed in a Minnesota state court. Each of the actions challenged the offer and merger and contained various allegations of wrongdoing on the part of the defendants in connection with the offer and the merger. In April 2002 counsel for the parties to the consolidated action in the Delaware Court of Chancery and the Minnesota action entered into a memorandum of understanding setting forth an agreement in principle to settle the actions based on the increase by us of the exchange ratio in the offer and merger from 0.4800 to 0.5000 Xcel Energy shares, but subject to confirmatory discovery, definitive documentation, and court approval. The Minnesota action has subsequently been dismissed without prejudice. As to the Delaware actions, the settlement has not been documented, approved or consummated, and in light of developments in the litigation that is described under Securities Class Action Litigation below, it is uncertain whether the settlement will ever proceed.

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

NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million conditional on the dismissal of the involuntary petition.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million.

On May 12, 2003, the Minnesota Bankruptcy Court issued an order abstaining from exercising jurisdiction over any aspect of the case and dismissed the case.

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

On July 1, 2002, we received a Notice of Violation from the EPA alleging violations of the NSR requirements at PSCo s 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 were non-routine major modifications and should have required a permit under the NSR process. We believe we acted in full compliance with the Clean Air Act and NSR process. We believe 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. We also believe that the projects would be expressly authorized under the EPA s NSR policy announced by the EPA administrator on June 22, 2002 and proposed in the Federal Register on December 31, 2002. We disagree with the assertions contained in the NOV and intend to vigorously defend our position. As required by the Clean Air Act, the EPA met with us in a conference 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 us 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 us is not determinable at this time.

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NSP-Minnesota Notice of Violation On December 10, 2001, the Minnesota Pollution Control Agency (MPCA) 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. The MPCA based its notice of violation in part on an EPA determination that the replacement constituted reconstruction of an affected facility under the Clean Air Act s New Source Review requirements. On June 27, 2003, the EPA rejected NSP-Minnesota s request for reconsideration of that determination. The New Source Performance Standard for coal handling systems is unlikely to require the installation of any emission controls not currently in place on the plant. It may impose additional monitoring requirements that would not have material impact on NSP-Minnesota or its operations. In addition, the MPCA or EPA may impose civil penalties for violations of up to $27,500 per day per violation. NSP-Minnesota is working with the MPCA to resolve the notice of violation.

Securities Class Action Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of our common stock between January 31, 2001 and July 26, 2002, was filed in the United States District Court in Minnesota. The complaint named us; Wayne H. Brunetti, Chairman and Chief Executive Officer; Edward J. McIntyre, former Vice President and Chief Financial Officer; and James J. Howard, former Chairman, as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Exchange Act and Rule 10b-5 thereunder related to allegedly false and misleading disclosures concerning various issues, including round trip energy trades, the existence of cross-default provisions in our and NRG s credit agreements with lenders, NRG s liquidity and credit status, the supposed risks to our credit ratings and the status of our internal controls to monitor trading of our power. Thereafter, 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 NRG senior notes issued by NRG in early 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 our credit agreements with lenders for cross-defaults in the event of a default by NRG and, as to the NRG senior notes, also insufficient disclosures concerning the extent to which NRG s fortunes were tied to those of Xcel Energy, especially in the event of a buy-in of NRG public shares. It adds as additional defendants on the claims related to the NRG senior notes Gary R. Johnson, Vice President and General Counsel, Richard C. Kelly, President and Chief Operating Officer, two former executive officers of NRG (David H. Peterson and Leonard A. Bluhm), one current executive officer of NRG (William T. Pieper) and a former independent director of NRG (Luella G. Goldberg); and, as to the NRG senior notes, it adds claims of similar false and misleading disclosures under Section 11 of the Securities Act of 1933. The defendants filed motions to dismiss all the claims, and the court granted the motions in part and denied them in part on September 30, 2003. In an order dated September 30, 2003, the court granted in part and denied in part the defendants motion to dismiss. The court dismissed the claims brought by a sub-class of plaintiffs represented by Catholic Workman. This group consisted of persons who purchased NRG senior notes and alleged false and misleading statements in the registration statement or prospectus under Section 11 of the Securities Act. The court, however, denied the motion with respect to a putative class of plaintiffs consisting of owners of Xcel Energy securities who alleged fraud in violation of Sections 10(b) and 20(a) of the Exchange Act. The defendants expect to file an answer on or about November 14, 2003, and the case is expected to proceed in the normal course as to the claims relating to common stock.

Shareholder Derivative Litigation On August 15, 2002, a shareholder derivative action was filed in the United States District Court for the District of Minnesota, purportedly on behalf of Xcel Energy, against our directors and certain present and former officers, citing essentially the same circumstances as the class actions described above and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with the securities class actions. After the filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota (and subsequently consolidated with each other), against essentially the same defendants, focusing on allegedly wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish and maintain adequate accounting controls, abuse of control and gross mismanagement. In each of the derivative cases, the defendants have served motions to dismiss the complaint for failure to make a proper pre-suit demand (or, in the federal court case, to make any pre-suit demand at all) upon our board of directors. On October 10, 2003 oral arguments related to the defendants motion to dismiss were presented to the court. The motion was based upon the defendants claim that the plaintiffs failed to satisfy the procedural prerequisites for commencing a shareholder derivative suit. The motion was taken under advisement by the court. None of the motions have yet been ruled upon.

ERISA Class Litigation On September 23, 2002 and October 9, 2002, actions were filed in the United States District Court for the District of Colorado, purportedly on behalf of classes of employee participants in our (and our predecessors) 401(k) and employee stock ownership plans from as early as September 23, 1999. The complaints in the actions, which name as defendants Xcel Energy, our directors, certain former directors, and certain of our present and former officers, allege breach of fiduciary duty in allowing or encouraging the purchase, contribution and/or retention of our common stock in the plans and making misleading statements and omissions in that regard. The cases have been transferred by the Judicial Panel on Multidistrict Litigation to the Minnesota federal court for purposes of coordination with the securities class actions and shareholder derivative action pending there. The defendants have filed motions to dismiss the complaints. The motions have not yet been ruled upon.

Stone/Shaw Litigation On October 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court for the Southern District of Mississippi against Xcel Energy; Wayne H. Brunetti, Chairman and Chief Executive Officer; Richard C. Kelly, President and Chief Operating Officer, and NRG and certain NRG subsidiaries. Plaintiffs allege they had a contract with a single purpose NRG subsidiary for the construction of a power generation facility, which was abandoned before completion but after substantial sums had been spent by plaintiffs. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy and aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The complaint seeks compensatory damages of at least $130 million plus demobilization and cancellation costs and punitive damages at least treble the compensatory damages. Defendants filed motions to dismiss which were denied, and certain defendants have moved for reconsideration on certain aspects of the motion. The parties have reached a settlement, which settlement is subject to approval by the bankruptcy court in the NRG bankruptcy; further activity in the litigation has been temporarily suspended pending that approval.

FirstEnergy Arbitration As discussed in Note 18 to the audited consolidated financial statements, in 2001, NRG had signed purchase agreements to acquire or lease a portfolio of generating assets from FirstEnergy Corporation. Under the terms of the agreements, NRG had agreed to finance approximately $1.6 billion for four primarily coal-fueled generating stations.

On July 2, 2002, the FERC issued an order approving the transfer of FirstEnergy generating assets to NRG; however, the FERC conditioned the approval on NRG s assumption of FirstEnergy s obligations under a separate agreement between FirstEnergy and the City of Cleveland. These conditions required FirstEnergy to protect the City of Cleveland in the event the generating assets are taken out of service. On July 16, 2002, FERC clarified that the condition would require NRG to provide notice to the City of Cleveland and FirstEnergy if the generating assets were taken out of service and that other obligations remain with FirstEnergy.

On August 8, 2002, FirstEnergy and other parties under the purchase agreements related to FirstEnergy generating assets (collectively, the sellers) notified NRG that the purchase agreements had been cancelled. The sellers cited the reason for canceling the agreements as an alleged anticipatory breach of certain obligations in the agreements by NRG. The sellers also notified NRG that they were reserving the right to pursue legal action against NRG and us for damages, based on the alleged anticipatory breach. On February 5, 2003, the sellers submitted filings with the U.S. Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On February 27, 2003, the sellers gave NRG notice that they were commencing arbitration against NRG to determine whether NRG is liable to the sellers for failure to close the transaction. The parties selected the arbitration panel and also obtained relief from stay respecting NRG s present Chapter 11 Bankruptcy, although the collection of any award will remain fully subject to NRG s automatic stay. The parties have now reached an agreement in principle, which, if consummated and approved by regulators and the bankruptcy court, would liquidate the seller s bankruptcy claim at $396 million.

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

Estimates of the ultimate cost to remediate the Ashland site vary from $4 million to $93 million, because different methods of remediation and different results are assumed in each. In the interim, NSP-Wisconsin has recorded a liability in the amount of $19 million for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, using information available to date and reasonably effective remedial methods.

The EPA and Wisconsin Department of Natural Resources have not yet selected the method of remediation to use at the site. On September 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 March 5, 2003, the EPA Region V notified NSP-Wisconsin that it would consider entering into an Administrative Order by Consent (AOC). NSP-Wisconsin responded to the EPA and the Wisconsin Department of Natural Resources on April 16, 2003 by proposing that NSP-Wisconsin be allowed to take over the completion of remedial investigation and feasibility studies (RI/ FS). On August 5, 2003, the EPA notified NSP-Wisconsin that it would enter into formal negotiations for the purpose of allowing NSP-Wisconsin to take over the completion of the RI/ FS. On August 26, 2003, NSP-Wisconsin submitted a good faith offer to complete the RI/ FS subject to the terms of the AOC. NSP-Wisconsin expects negotiations will be concluded shortly.

California Litigation On March 11, 2002, the Attorney General of California filed in federal court, United States District Court for the Northern District of California, a civil complaint against NRG, certain NRG affiliates, us, Dynegy, Inc. and Dynegy Power Marketing, Inc., alleging antitrust violations in the ancillary services market. The complaint alleges that the defendants repeatedly sold electricity generating capacity to the California Independent System Operator for use as a reserve and subsequently, and impermissibly, sold the same capacity into the spot market for wholesale power, unlawfully collecting millions of dollars. Similar complaints were filed against other power generators. The plaintiff seeks an injunction against further similar acts by the defendants, and also seeks restitution, disgorgement of all proceeds, including profits, gained from these sales, and certain civil penalties. On April 17, 2002, the defendants in these various cases removed all of them to the federal district court, which denied the Attorney General s motion to remand the cases to state court. That decision is on appeal to the Ninth Circuit Court. Meanwhile, the defendants motion to dismiss all the cases based on federal preemption and the filed rate doctrine is pending in the district court. A notice of bankruptcy filing regarding NRG has also been filed in this action, providing notice of the involuntary petition. On March 25, 2003, the federal district court dismissed the Attorney General s actions against NRG, certain NRG affiliates, Dynegy, Inc. and Dynegy Power Marketing, Inc. without prejudice. The decision has been appealed to the Ninth Circuit, which has scheduled oral arguments for later this year.

Public Utility District No. 1 of Snohomish County, Washington, has filed a suit in the United States Circuit Court for the Northern District of California against Xcel Energy contending that various of its trading strategies, as reported to the FERC in response to that agency s investigation of trading strategies discussed above, violated the California Business and Professions Code. Public Utility District No. 1 of Snohomish County contends that the effect of those strategies was to increase amounts that it paid for wholesale power in the spot market in the Pacific Northwest. Xcel Energy and other defendants requested the case be dismissed in its entirety. In an order dated January 6, 2003, the District Court dismissed the County s claim. The decision has been appealed to the Ninth Circuit, which has scheduled oral arguments for later this year.

Two separate class action lawsuits were also filed in Washington (Symonds v. Xcel Energy, et al.) and Oregon (Lodewick v. Xcel Energy, et al.) alleging unfair competition similar to those filed in California. Both lawsuits named Xcel Energy and NRG as defendants and have been voluntarily dismissed by the plaintiffs.

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In addition, the California Attorney General s Office has informed PSCo that it may raise claims against PSCo under the California Business and Professions Code with respect to the rates that PSCo has charged for wholesale sales and PSCo s reporting of those charges to the FERC. PSCo has had preliminary discussions with the California Attorney General s Office, and has expressed the view that FERC is the appropriate forum for the concerns that it has raised.

Home Builders Association of Metropolitan Denver On February 23, 2001, Home Builders Association of Metropolitan Denver (HBA) filed a formal complaint with the CPUC, requesting an award of reparations for excessive charges related to construction payments under PSCo s gas extension tariff as a result of PSCo s alleged failure to file revisions to its published construction allowances since 1996. HBA seeks an award of reparations on behalf of all of PSCo s gas extension applicants since October 1, 1996, in the amount of $13.6 million, including interest. HBA also seeks recovery of its attorneys fees.

Hearings were held before an administrative law judge (ALJ) on August 29 and September 24, 2001. On January 15, 2002, the ALJ issued his Recommended Decision dismissing HBA s complaint. The ALJ found that HBA failed to show that there have been any excessive charges, as required under the reparations statute, resulting from PSCo s failure to comply with its tariff. The ALJ held that HBA s claim for reparations (i) was barred by the filed rate doctrine (since PSCo at all times applied the approved construction allowances set forth in its tariff), (ii) would require the Commission to violate the prohibition against retroactive ratemaking, and (iii) was based on speculation as to what the Commission would do had PSCo made the filings in prior years to change its construction allowances. The ALJ also denied HBA s request for costs and attorneys fees. HBA filed exceptions to the ALJ s decision. On June 19, 2002, the CPUC issued an order granting in part HBA s exceptions to the ALJ s recommended decision and remanding the case back to the ALJ for further proceedings. The CPUC reversed the ALJ s legal conclusion that the filed rate doctrine and prohibition against retroactive ratemaking bars HBA s claim for reparations under the circumstances of this case. The CPUC remanded the case back to the ALJ for a determination of whether and to what extent due reparations should be awarded, considering certain enumerated issues.

On May 15, 2003, the ALJ issued a recommended decision. On the remanded issues, the ALJ determined that HBA is able to seek an award of reparations on behalf of its member homebuilders. However, the ALJ further determined the construction allowance applied by PSCo from 1996 through 2002 was neither excessive nor discriminatory, and that HBA failed to meet its burden to show that its method of calculating reparations for the period 1996 through 2002 is proper.

On August 27, 2003, the CPUC issued its ruling with respect to this matter and on September 24, 2003 adopted a written order in this proceeding. According to the CPUC decision:

PSCo should have been required to change its construction allowance from $360 to $381 as a result of the final determination in Phase I of its 1997 general rate case;

PSCo should file a plan to pay reparations to HBA members based on a revised $381 construction allowance for the period February 24, 1999 through May 31, 2002. The plan should take into account the most cost-effective way to reduce the burden of making detailed transaction-specific calculations versus a more general approach that does not unreasonably compromise the level of each refund;

Interest should be applied based on the customer deposit rate; and

PSCo over earned during the relevant time period and is prohibited from future recovery of the reparation costs.

The level of reparations based on a $381 construction allowance is not known at this time. However, management expects that such reparations are likely to be less than $1.5 million. PSCo and HBA have both requested rehearing of the August 27, 2003 CPUC order.

SchlumbergerSema, Inc. Under a 1996 Data Services Agreement (DSA), 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 events of default had occurred under the DSA, including SLB s nonpayment of approximately $7.4 million for distribution automation assets.

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In November 2002, SLB demanded arbitration before the American Arbitration Association and asserted various claims against NSP-Minnesota totaling $24 million for NSP-Minnesota s alleged breach of an expansion contract and a meter purchasing contract. In the arbitration, NSP-Minnesota asserts counterclaims against SLB for SLB s failure to meet performance criteria, improper billing, failure to pay for use of NSP-owned property, and failure to pay $7.4 million for NSP-Minnesota distribution automation assets. NSP-Minnesota also seeks a declaratory judgment from the arbitrator that will terminate SLB s rights under the DSA. The parties are scheduled to arbitrate the dispute beginning March 1, 2004.

Lamb County Electric Cooperative On July 24, 1995, Lamb County Electric Cooperative, Inc. (LCEC) petitioned the PUCT for a cease and desist order against SPS. LCEC alleged that SPS had been unlawfully providing service to oil field customers and their facilities in LCEC s singly certificated area. Lamb County also has sued Xcel Energy in Texas state court. In April 2003, the PUCT approved a recommended proposal for decision. Xcel Energy defended its service by demonstrating that in 1976 the cooperatives, Xcel Energy and the PUCT intended that Xcel Energy was to serve the expanding oil field operations. Xcel Energy demonstrated through extensive research that it was serving each of the oil field units and leases back in 1975, and it was not serving new customers. The PUCT decided that Xcel Energy was authorized to serve the oil field operations and denied LCEC s request for a cease- and desist-order. LCEC has appealed to state court the PUCT s denial of LCEC s petition.

St. Cloud Gas Explosion Twenty-five lawsuits have been filed as a result of a December 11, 1998 gas explosion that killed four persons (including two employees of NSP-Minnesota), injured several others and damaged numerous buildings. Most of the lawsuits name as defendants, NSP-Minnesota, Seren, Cable Constructors, Inc. (CCI) (the contractor that struck the marked gas line) and Sirti, an architectural/ engineering firm hired by Seren for its St. Cloud cable installation project. The court granted the plaintiffs request to amend the complaint to seek punitive damages against Seren and CCI. The plaintiffs brought a similar motion against NSP-Minnesota, which was subsequently denied by the court. On November 11, 2003, court-ordered mediation was conducted. As a result of this mediation, NSP-Minnesota reached a confidential settlement with a group of plaintiffs representing most significant claims against NSP-Minnesota. The settlements will be paid by NSP-Minnesota s insurance carrier. A trial date has not been set for the remaining lawsuits.

Colorado Wildfires In late October 2003, there were two wildfires in Colorado, one in Boulder County and the other in Douglas County. There was no loss of life, but there was property damage associated with these fires. Parties have asserted that one or both fires may have been caused by trees falling into PSCo distribution lines. We are in the very preliminary stages of investigation as to the cause of each fire. It is reasonable likely that there will be future litigation relating to these fires and such litigation could be material.

Department of Labor Audit In 2001, we received notice from the Department of Labor Employee Benefit Security Administration (DOL) that it intended to audit the Xcel Energy Pension Plan. After multiple on-site meetings and interviews with company personnel, the DOL indicated on September 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, breach its fiduciary duties under the Employee Retirement Income Security Act of 1974, as amended, with respect to certain investments made in limited partnerships and hedge funds in 1997 and 1998.

All discussions related to potential fiduciary violations have been preliminary and unofficial. The DOL has offered to conclude the audit at this time if we are willing to contribute to the plan the full amount of losses from each of these questioned investments, or approximately $13 million. We have responded with a letter to the DOL asserting no fiduciary violations have occurred, and extending an offer to meet to discuss the matter further.

For a discussion of other legal claims and environmental proceedings, see Note 18 to the audited consolidated financial statements and Note 8 to the interim consolidated financial statements. For a discussion of proceedings involving utility rates, see Business Pending Regulatory Matters.

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MANAGEMENT

The following table sets forth certain information about our directors and executive officers as of October 31, 2003.

Name	Age	Position
Wayne H. Brunetti	60	Chairman of the Board, Chief Executive Officer and Director
Richard C. Kelly	57	President and Chief Operating Officer
Paul J. Bonavia	52	President Energy Markets
Cathy J. Hart	54	Vice President and Corporate Secretary
Gary R. Johnson	56	Vice President and General Counsel
Cynthia L. Lesher	55	Chief Administrative Officer
Raymond E. Gogel	53	Vice President and Chief Information Officer
Benjamin G.S. Fowke, III	45	Vice President, Chief Financial Officer and Treasurer
David E. Ripka	54	Vice President and Controller
Patricia K. Vincent	44	President Energy Customer and Field Operations
David M. Wilks	56	President Energy Supply
C. Coney Burgess	65	Director
David A. Christensen	68	Director
Roger R. Hemminghaus	67	Director
A. Barry Hirschfeld	61	Director
Douglas W. Leatherdale	66	Director
Albert F. Moreno	59	Director
Dr. Margaret R. Preska	65	Director
A. Patricia Sampson	54	Director
Allan L. Schuman	69	Director
Rodney E. Slifer	68	Director
W. Thomas Stephens	61	Director

Directors and Executive Officers

Wayne H. Brunetti is Chairman and Chief Executive Officer of Xcel Energy Inc. He has served as Chairman since August 18, 2001 and as Chief Executive Officer from the completion of our Merger on August 18, 2000. From the completion of our Merger until October 2003, Mr. Brunetti also served as our President. Mr. Brunetti has been a Director of Xcel Energy Inc. since 2000. From March 1, 2000 until the completion of the Merger, he served as Chairman, President and Chief Executive Officer of NCE and as a director and officer of several of NCE s subsidiaries. From August 1997 until March 1, 2000, Mr. Brunetti was Vice Chairman, President and Chief Operating Officer of NCE. Before the merger of PSCo and SPS to form NCE, Mr. Brunetti was President and CEO of PSCo. He joined PSCo in July 1994 as President and Chief Operating Officer. In January 1996, he added the title of CEO. Mr. Brunetti is the former President and CEO of Management Systems International, a Florida management consulting firm that he founded in 1991. Prior to that, he was Executive Vice President of Florida Power & Light Company. Mr. Brunetti has been active in various professional and civic groups. He currently serves as a vice-chairman of Edison Electric Institute and serves on its board, executive committee, policy committee on energy services and policy committee on energy supply. He serves on the boards of Medic Alert Foundation, Capital City Partnership and the Minnesota Orchestra. He is past chairman of the 2000 Mile High United Way campaign, past chairman of the board of

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the Colorado Association of Commerce and Industry and served on the Colorado Association of Commerce and Industry and served on the Colorado Renewable Energy Task Force, an appointment made by Governor Roy Romer. He is the author of *Achieving Total Quality in Integrated Business Strategy & Customer Needs*. Mr. Brunetti holds a bachelor of science degree in business administration from the University of Florida. He is a graduate of the Harvard Business School s Program for Management Development.

Richard C. Kelly has been our President and Chief Operating Officer since October 2003. Previously, Mr. Kelly was our Vice President and Chief Financial Officer from August 2002 to October 2003 and our President Enterprises from August 2000 to August 2002. Mr. Kelly also served as Executive Vice President and Chief Financial Officer for NCE from 1997 to August 2000 and Senior Vice President of PSCo from 1990 to 1997.

Paul J. Bonavia has been our President Energy Markets since August 2000. Previously, Mr. Bonavia served as Senior Vice President and General Counsel of NCE from 1997.

Cathy J. Hart has been our Vice President and Corporate Secretary since August 2000. Previously, Ms. Hart served as Secretary of NCE from 1998 and as Manager of Corporate Communications of PSCo from 1993 to 1996. For family reasons, Ms. Hart resigned as Manager of Corporate Communications at PSCo in June 1996 to move to Australia. From June 1996 to June 1998, Ms. Hart was not employed. She was re-employed by NCE as Corporate Secretary in June 1998.

Gary R. Johnson has been our Vice President and General Counsel since August 2000. Previously, Mr. Johnson served as Vice President and General Counsel of NSP from 1991.

Cynthia L. Lesher has been our Chief Administrative Officer since August 2000. She has also been our Chief Human Resources Officer since July 2001. Previously, Ms. Lesher served as President of NSP-Gas from July 1997 and previously Vice President-Human Resources of NSP.

Raymond E. Gogel has been our Vice President and Chief Information Officer since April 2002. Previously, Mr. Gogel was Vice President and Senior Client Services Principal for IBM Global Services since June 2001 and Senior Project Executive for IBM s Global Services since January 1998.

Benjamin G.S. Fowke, III has been our Chief Financial Officer since October 2003 and our Vice President and Treasurer since November 2002. Previously, Mr. Fowke served as Vice President and Chief Financial Officer of our commodity trading and marketing business unit from 2000. He was Vice President of Retail Services and Energy Markets at NCE from January 1999 to July 2000 and Vice President-Finance/ Accounting at e prime from May 1997 to December 1998.

David E. Ripka has been our Vice President and Controller since August 2000. Previously, Mr. Ripka served as Vice President and Controller of NRG from June 1999 to August 2000, Controller of NRG from March 1997 to June 1999 and Assistant Controller for NSP from June 1992 to March 1997.

Patricia K. Vincent has been our President Energy Customer and Field Operations since July 2003. Previously, Ms. Vincent served as our President Retail Services from March 2001 to July 2003, Vice President of Marketing and Sales from August 2000 to March 2001, Vice President of Marketing & Sales of NCE from January 1999 to August 2000 and Manager, Director and Vice President of Marketing and Sales at Arizona Public Service Company from 1992 to January 1999.

David M. Wilks has been our President Energy Supply since August 2000. Previously, Mr. Wilks served as Executive Vice President and Director of PSCo and New Century Services from 1997 to August 2000 and President, Chief Operating Officers and Director of SPS from 1995 to August 2000.

C. Coney Burgess has been a Director of Xcel Energy Inc. since 2000. He is Chairman of the board of directors of Herring Bancorp, a national bank holding company based in Vernon, Texas. He is also Chairman of the board of Herring Bancshares, Inc., a holding company in Oklahoma. He has served as Chairman of Herring Bancorp and Herring Bancshares since 1992. Mr. Burgess is Chairman/ President of Burgess-Herring Ranch Company, a position he has held since 1974, and Chain-C, Inc., an agricultural firm with operations in the Texas Panhandle. He is President of Monarch Trust Company in Amarillo, Texas, and Chairman of the

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Herring National Bank. He served on the board of directors of NCE from 1997 until 2000. Mr. Burgess also served on the board of directors of SPS from 1994 to 1997. Mr. Burgess is past President of Texas and Southwestern Cattle Raisers Association in Forth Worth, Texas, and is a director of the American Quarter Horse Association, Cattlemans Beef Board, National Cattlemans Beef Association and Panhandle Livestock Association. He is on the board of overseers and the board of endowment of the Ranching Heritage Association at Texas Tech University in Lubbock, Texas, and Harrington Cancer Center in Amarillo, Texas. Mr. Burgess is past Chairman of the Board of Cal Farley s Boys Ranch and Affiliates; a board member of the Boys Ranch Foundation; past President of the Amarillo Symphony; past President of the Amarillo Downtown Rotary; a trustee of Marine Military Academy; and an advisory Board member for Texas Tech University, College of Agricultural Sciences, Lubbock, Texas. Mr. Burgess received his B.S. and B.A. from Mississippi State University and attended law school at the University of Mississippi.

David A. Christensen has been a Director of Xcel Energy Inc. since 1976. He served as President and Chief Executive Officer of Raven Industries, Inc., Sioux Falls, South Dakota, an industrial manufacturer that provides electronics manufacturing services, reinforced plastic sheeting and flow control devices in various markets from 1971 until his retirement in August 2000 and continues as a director. He has been associated with Raven Industries since 1962, and also worked at John Morrell & Co. and served in the U.S. Army Corps of Engineers. He received his bachelors degree in industrial engineering from South Dakota State University, which later honored him with its distinguished engineer, distinguished service, and distinguished alumni awards. In 2000, Mr. Christensen received the Sioux Falls Development Foundation s Spirit of Sioux Falls award. Inducted into the South Dakota Hall of Fame in 1998, Mr. Christensen was presented with the Executive of the Year Award by Sales and Marketing Executives, Inc. of Sioux Falls, South Dakota in 1993, and was University of South Dakota s South Dakotan of the Year in 1985. Mr. Christensen also serves as a director of Wells Fargo & Co., San Francisco, California and Medcomp Software, Inc., Colorado Springs, Colorado. A strong advocate for his community and state, he has served in many volunteer activities. He is a past director of the South Dakota Symphony and Sioux Falls Downtown Development Corp., as well as a past chairman of the Sioux Empire United Way.

Roger R. Hemminghaus has been a Director of Xcel Energy Inc. since 2000. He retired as Chairman of the Board of Ultramar Diamond Shamrock Corporation in January 2000 and as Chief Executive Officer in January 1999. Mr. Hemminghaus had become Chairman and CEO of Ultramar Diamond Shamrock Corporation following the merger of Diamond Shamrock, Inc. and Ultramar Corporation in 1996. Prior to the merger, Mr. Hemminghaus was Chairman, CEO and President of Diamond Shamrock, Inc. He started his career in the energy industry in 1962 as an engineer for Exxon, USA, after serving four years as a naval officer involved in nuclear power development. Mr. Hemminghaus served as a Director of NCE from 1997 until 2000 and on the SPS board of directors from 1994 until 1997. He is on the boards of directors of Luby s, Inc., CTS Corporation and Tandy Brands Accessories Incorporated. Mr. Hemminghaus is Chairman of the Southwest Research Institute. He is former Chairman of the Federal Reserve Bank of Dallas and former Chairman of the National Petrochemicals and Refiners Association. He is Chairman of the Board of Regents of Texas Lutheran University; he serves on the National Executive Board of the Boy Scouts of America and serves on various other non-profit association boards. Mr. Hemminghaus is a 1958 graduate of Auburn University, receiving a B.S. degree in chemical engineering and has done graduate work in business and nuclear engineering.

A. Barry Hirschfeld has been a Director of Xcel Energy Inc. since 2000. He is President of A.B. Hirschfeld Press, Inc., a commercial printing company. He has held this position since 1984 and is the third generation to head this family-owned business, which was founded in 1907. He received his M.B.A. from the University of Denver and a B.S. in business administration from California State Polytechnic University. Mr. Hirschfeld served on the NCE board from 1997 until 2000 and on the board of directors of PSCo from 1988 to 1997. He serves on the boards of directors of the Mountain States Employers Council; the Denver Area Council of Boy Scouts of America, where he serves on the Board Affairs Committee; the Rocky Mountain Multiple Sclerosis Center; Colorado s Ocean Journey; the Cherry Creek Arts Festival; Up With People; and the National Jewish Center. He also serves on the advisory board of the Harvard University Divinity School Center for Values in Public Life. Mr. Hirschfeld is Executive Vice President of the Mile Hi

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Stadium Club; a member of the One Hundred Club of Denver; Colorado Concern, where he serves on the executive committee; the Colorado Forum; and Mayor Wellington Webb s Advisory Committee. He is past board Chairman and lifetime board member of the Denver Metro Convention and Visitors Bureau, past Trustee of the Boettcher Foundation, and past Chairman of the Denver Art Museum.

Douglas W. Leatherdale has been a Director of Xcel Energy Inc. since 1991. He is the retired Chairman and Chief Executive Officer of The St. Paul Companies, Inc., a worldwide property and liability insurance organization. Mr. Leatherdale joined The St. Paul Companies in 1972 and has held numerous executive positions with the Company, including President, Executive Vice President and Senior Vice President of Finance. He held the position of Chairman and Chief Executive Officer from 1990 until his retirement in 2001. Before joining The St. Paul Companies, Mr. Leatherdale was employed by the Lutheran Church of America in Minneapolis where he served as Associate Executive Secretary on the Board of Pensions. Prior to his four years at the Lutheran Church of America, he served as Investment Analyst Officer at Great West Life Assurance Company in Winnipeg. A native of Canada, Mr. Leatherdale attended United College in Winnipeg (now the University of Winnipeg) and later completed additional studies at Harvard Business School and The University of California-Berkeley. In 2000, he was awarded a Doctorate of Laws degree (honoris causa) from The University of Winnipeg. Mr. Leatherdale also serves as a director of United HealthCare Group. He is the Chairman of the Board of Directors of the International Insurance Society and The Minnesota Orchestral Association. He is the past Chairman of the University of Minnesota Foundation and the American Insurance Association.

Albert F. Moreno has been a Director of Xcel Energy Inc. since 1999. He is Senior Vice President and General Counsel of Levi Strauss & Co. (LS&CO), a brand name apparel manufacturer. Mr. Moreno is directly responsible for LS&CO s legal and brand protection affairs and oversees the company s global security and government affairs departments. He has held this position since 1996. Mr. Moreno joined LS&CO in 1978 as Assistant General Counsel. In addition to his work with LS&CO, Mr. Moreno is a member of the Rosenberg Foundation and the Levi Strauss Foundation. He served on the NCE board of directors from 1999 until the completion of our merger in 2000. Mr. Moreno received a bachelor s degree in economics from San Diego State University in 1966 and a degree in Latin American Economic Studies from the Universidad de Madrid in 1967. In 1970, he received his law degree from the University of California at Berkeley School of Law.

Dr. Margaret R. Preska has been a Director of Xcel Energy Inc. since 1980. She is the President Emerita, Minnesota State University, Mankato and Distinguished Service Professor, Minnesota State Universities. Dr. Preska served as founding campus CEO at Zayed University, Abu Dhabi, United Arab Emirates from 1998 to 2000. She was a member of the history faculty at Winona State University and let a research project at the University of Kaleningrad in Russia from 1992 to 1998. She was President of Minnesota State University, Mankato, from 1979 until 1992. She had served as its Vice President for Academic Affairs and Equal Opportunity Officer from 1975 until 1979. She previously was academic dean, instructor, assistant and associate professor of history and government at LaVerne College in LaVerne, California. She is owner/ president of an internet-based instructional business, Build a Bike Inc. com. Dr. Preska earned a bachelor of science degree at SUNY Brockport, where she graduated *summa cum laude*. She earned a master s at The Pennsylvania State University, a Ph.D. at Claremont Graduate University, and further studied at Manchester College of Oxford University. Dr. Preska is a member of Women Directors and Officers in Public Utilities and is a member of the board of directors of Milkweed Editions, a literary and educational publisher. She served as national President at Camp Fire Boys and Girls, Inc. from 1985 until 1987. She is a charter member of the board of directors of Executive Sports, Inc., a division of Golden Bear International. She is affiliated with several organizations, including the Retired Presidents Association of the American Association of State Colleges and Universities, the St. Paul/Minneapolis Committee on Foreign Relations, Rotary, Minnesota Women s Economic Roundtable, the American Historical Association and Horizon 100.

A. Patricia Sampson has been a Director of Xcel Energy Inc. since 1985. She currently operates The Sampson Group, Inc., a management development and strategic planning consulting business. Prior to that she served as a consultant with Dr. Sanders and Associates, a management and diversity consulting company.

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Prior to her current endeavors, Ms. Sampson served as Chief Executive Officer of the Greater Minneapolis Area Chapter of the American Red Cross from July 1993 until January 1, 1995. She also previously served successively as Executive Director from October 1986 until July 1993, Assistant Executive Director-Services (April 1985), and Assistant Manager (July 1984) of the Greater Minneapolis Area Chapter. Prior to the above, she served as the Director of Service to Military Families and Veterans and Director of Disaster Services for the St. Paul Area Chapter of the American Red Cross. Ms. Sampson received a masters degree from the University of Pennsylvania and a bachelors degree from Youngstown State University. She previously served on the David W. Preus Leadership Award Sponsoring Council as well as on the boards of the Greater Minneapolis Area United Way, Minneapolis Urban League, the Minnesota Orchestral Association, and the Minnesota Women s Economic Roundtable. She is active in Christian education.

Allan L. Schuman has been a Director of Xcel Energy Inc. since 1999. He is Chairman of the Board, Chief Executive Officer, President and a director of Ecolab Inc. in St. Paul, Minnesota. Ecolab develops and manufactures cleaning, sanitizing, and maintenance products for the hospitality, institutional, and industrial markets. Mr. Schuman joined Ecolab in 1957, and became Vice President, Institutional Marketing and National Accounts in 1972. In 1985 he was named Executive Vice President and in 1988, President, Ecolab Services Group. He was promoted to President and Chief Operating Officer of Ecolab in August 1992 and named President and Chief Executive Officer in March 1995. Mr. Schuman serves as a director of the Soap and Detergent Association, National Association of Manufacturers, Hazelden Foundation, the Ordway Music Theatre, the Guthrie Theatre, and the Capital City Partnership. He is also a Trustee of the Culinary Institute of America and of the National Education Foundation of the National Restaurant Association, and a member of the board of overseers of Carlson School of Management at the University of Minnesota. He is a member of the Board of Trustees of Hamline University.

Rodney E. Slifer has been a Director of Xcel Energy Inc. since 2000. He is a Partner in Slifer, Smith & Frampton, a diversified real estate company in Vail, Colorado. He has held this position since 1989. Mr. Slifer served on the NCE Board from 1997 until 2000 and on the PSCo board from 1988 until 1997. In addition, he currently is a director of Alpine Banks of Colorado. He is Vice President and a board member of the Vail Valley Foundation and a director of Colorado Open Lands. Mr. Slifer also is a member of the Board of Governors of the University of Colorado Real Estate Center and a member of the University of Colorado Real Estate Foundation Board of Directors.

W. Thomas Stephens has been a Director of Xcel Energy Inc. since 2000. He retired in 1999 as President and CEO of MacMillan Bloedel Ltd., a forest products and building materials company with headquarters in Vancouver, British Columbia. He served as Chairman, President and CEO of Johns Manville, an international manufacturing and natural resources company located in Denver, Colorado, from 1986 until August 1996. Mr. Stephens served on the NCE board of directors from 1997 until 2000 and on the PSCo board from 1989 until 1997. He is on the boards of directors of TransCanada Pipeline, Norske Canada Ltd., Qwest Communications International Inc., Mail-Well Inc., and The Putnam Funds. He received his bachelor s and master s degrees in industrial engineering from the University of Arkansas.

Board Structure and Compensation

Our Board currently consists of twelve directors.

The Board had the following four Committees during 2002: Audit, Finance, Governance, Compensation and Nominating, and Operations and Nuclear. The membership during 2002 and the function of each Committee are described below. During 2002, the Board met 21 times and various Committees of the Board met as indicated below. Each director attended at least 75 percent of the meetings of the Board and Committees on which such director served during 2002.

Audit Committee

Members: Roger R. Hemminghaus (Chair), Albert F. Moreno, Margaret R. Preska, Allan L. Schuman, and Rodney E. Slifer.

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Number of meetings in 2002: 7.

Function:

Oversees the accounting and financial reporting processes;

Oversees the internal control structure;

Oversees the integrity of financial statements and other financial information provided to shareholders;

Oversees compliance with legal and regulatory requirements;

Oversees performance of the internal audit function and independent external auditors; and

Reviews the qualifications and oversees the independence of the independent external auditors.

The Audit Committee operates under a written Charter adopted by our Board of Directors. The Charter was amended June 24, 2003 in response to the requirements of the Sarbanes-Oxley Act and the New York Stock Exchange.

Finance Committee

Members: Douglas W. Leatherdale (Chair), C. Coney Burgess, A. Barry Hirschfeld, Margaret R. Preska, Allan L. Schuman, and W. Thomas Stephens.

Number of meetings in 2002: 4.

Function:

Oversees corporate capital structure and budgets;

Oversees financial plans and dividend policies;

Recommends dividends;

Oversees insurance coverage and banking relationships;

Oversees investor relations;

Oversees risk management; and

Oversees dedicated funds, including ERISA plans and nuclear decommissioning fund.

Governance, Compensation and Nominating Committee

Members: W. Thomas Stephens (Chair), C. Coney Burgess, David A. Christensen, A. Barry Hirschfeld, Douglas W. Leatherdale, and A. Patricia Sampson.

Number of meetings in 2002: 4.

Function:

Identifies individuals qualified to become board members;

Recommends candidates to fill board vacancies and newly-created director positions;

Recommends whether incumbent directors should be nominated for re-election to the board; and

Develops and recommends corporate governance principles applicable to the board and our employees.

The Governance, Compensation and Nominating Committee charter was amended August 26, 2003 in response to the requirements of the Sarbanes-Oxley Act and the New York Stock Exchange. Any shareholder may make recommendations to the Governance, Compensation and Nominating Committee for Membership on the Board by sending a written statement of the qualifications of the recommended individual to the Secretary of the Company at 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota 55402-2023.

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Operations and Nuclear Committee

Members: David A Christensen (Chair), Roger R. Hemminghaus, Albert G. Moreno, A. Patricia Sampson and Rodney E. Slifer.

Number of meetings in 2002: 3.

Function:

Oversees nuclear and non-nuclear operations, electric and gas delivery and retail service operations;

Reviews environmental compliance;

Reviews safety and operations performance; and

Reviews operational decisions and plans related to performance.

Directors Compensation

The following table provides information on our compensation and reimbursement practices during 2002 for nonemployee directors. The director who is employed by us, Mr. Wayne Brunetti, does not receive any compensation for his Board activities.

Directors Compensation for 2002

Annual Director Retainer	$33,600
Board Meeting Attendance Fees (per meeting)	$ 1,200
Telephonic Meeting Attendance Fees (per meeting)	$ 500
Committee Meeting Attendance Fees (per meeting)	$ 1,200
Additional Retainer for Committee Chair (Governance, Compensation & Nominating Committee and Operations & Nuclear Committee)	$ 3,000
Additional Retainer for Audit Committee(1)	$ 4,250
Additional Retainer for Finance Committee(2)	$ 3,834
Stock Equivalent Units	$52,800

(1) Audit Committee chair s annual retainer was increased from $3,000 to $6,000 effective August 2002.

(2) Finance Committee chair s annual retainer was increased from $3,000 to $5,000 effective August 2002.

We have a Stock Equivalent Plan for Non-Employee Directors to more closely align directors interests with those of our shareholders. Under this Stock Equivalent Plan, directors may receive an annual award of stock equivalent units with each unit having a value equal to one share of our common stock. Stock equivalent units do not entitle a director to vote and are only payable as a distribution of whole shares of our common stock upon a director s termination of service. The stock equivalent units fluctuate in value as the value of our common stock fluctuates.

Additional stock equivalent units are accumulated upon the payment of and at the same value as dividends declared on our common stock. On April 19, 2002, our non-employee directors received an award of 2,039.40 stock equivalent units representing approximately $52,800 in cash value.

Additional stock equivalent units were accumulated during 2002 as dividends were paid on our common stock. The number of stock equivalents for each non-employee director is listed in the share ownership chart which is set forth below.

Directors also may participate in a deferred compensation plan which provides for deferral of director retainer and meeting fees until after retirement from the Board. A director may defer director retainer and meeting fees into the Stock Equivalent Plan. A director who elects to defter compensation under this plan receives a premium of 20 percent of the compensation that is deferred.

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Common Stock Ownership of Directors and Executive Officers

The following table sets forth information concerning beneficial ownership of our common stock as of September 30, 2003, for: (a) each director; (b) Named Executive Officers set forth in the Summary Compensation Table; and (c) the directors and executive officers as a group. Unless otherwise indicated, each person has sole investment and voting power (or shares such powers with his or her spouse) with respect to the shares set forth in the following table. None of the individuals listed in the Beneficial Ownership Table below own more than 0.21 percent of our common stock. None of these individuals owns any shares of our preferred stock.

Beneficial Ownership Table

Name and Principal Position of Beneficial Owner	Common Stock	Stock Equivalents	Options Exercisable Within 60 Days	Restricted Stock	Total
Wayne H. Brunetti Chairman of the Board and Chief Executive Officer	108,217.64	12,807.46	692,850.00	24,972.51	838,847.61
C. Coney Burgess Director	8,794.53	18,073.50			26,868.03
David A. Christensen Director	1,000.00	42,068.68			43,068.68
Roger R. Hemminghaus Director	6,585.07	27,896.95			34,482.02
A. Barry Hirschfeld Director	13,589.09	20,206.27			33,795.36
Douglas W. Leatherdale Director	1,100.00	40,874.29			41,974.29
Albert F. Moreno Director	4,325.00	26,461.94			30,786.94
Margaret R. Preska Director	1,300.00	30,637.26			31,937.26
A. Patricia Sampson Director	1,286.08	27,709.16			28,995.24
Allan L. Schuman Director	200.00	25,828.71			26,028.71
Rodney E. Slifer Director	18,391.80	30,459.48			48,851.28
W. Thomas Stephens Director	11,291.38	26,903.99			38,195.37
Paul J. Bonavia President, Energy Markets	5,626.38	1,440.07	186,000.00		193,066.45
David M. Wilks President, Energy Supply	32,060.14	4,064.80	173,600.00	4,921.69	214,646.63
James T. Petillo(1) President, Energy Delivery	17,478.91	1,304.59	112,530.00		131,313.50
Gary R. Johnson Vice President and General Counsel	20,201.92		109,505.00		129,706.92
Richard C. Kelly(2) President and Chief Operating Officer(3)	29,704.83	3,533.02	224,750.00	3,276.32	261,264.17
Directors and Executive Officers as a group (24 persons)(4)	345,668.60	343,464.77	1,717,756.00	34,967.46	2,441,856.83

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(1) Mr. Petillo terminated his employment on August 31, 2003.
(2) Mr. Kelly s wife owns 407.84 of these shares. Mr. Kelly disclaims beneficial ownership of these shares.

(3) Mr. Kelly was elected President and Chief Operating Officer in October 2003.

(4) Includes amounts beneficially owned by James T. Petillo, former President, Energy Delivery, who terminated his employment on August 31, 2003.

Executive Compensation

The following tables set forth cash and non-cash compensation for each of the last three fiscal years ended December 31, 2002, for our Chief Executive Officer, each of the five next most highly compensated executive officers serving as officers at December 31, 2002 (collectively, the Named Executive Officers). As set forth in the footnotes, the data presented in this table and the tables that follow include amounts paid to the Named Executive Officers in 2002 by us or any of our subsidiaries, as well as by NCE and NSP or any of their subsidiaries for the period prior to the Merger.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Name and Principal Position	Year	Salary($)	Bonus($)(1)	Other Annual Compensation ($)(2)	Restricted Stock Awards ($)(3)	Number of Securities Underlying Options and SAR s(#)(4)	LTIP Payouts ($)(5)	All Other Compensation ($)(6)
Wayne H. Brunetti	2002	1,065,000		9,836				95,832
Chairman and	2001	895,000	953,873	9,267			902,271	81,360
Chief Executive Officer	2000	756,667	852,244	167,265		756,000		314,436
Richard C. Kelly	2002	510,000		3,814				45,917
Vice President and	2001	425,417	338,588	1,208			269,633	39,077
Chief Operating Officer*	2000	375,917	279,446	55,855		228,000		130,124
Gary R. Johnson	2002	390,000		1,329				26,656
Vice President and	2001	340,000	236,656	3,934			175,206	27,640
General Counsel	2000	313,750	240,378	3,613		185,188		25,409
Paul J. Bonavia	2002	385,000		3,956				9,278
President,	2001	350,000	262,920	15,416			180,338	16,503
Energy Markets	2000	325,500	218,074	2,182		153,000		14,258
James T. Petillo**	2002	345,000		1,617				15,157
President,	2001	316,250	200,463	12,978			149,408	15,562
Energy Delivery	2000	249,167	163,582	7,596		126,000		12,877
David M. Wilks	2002	345,000		2,041				27,545
President,	2001	310,000	216,202	3,994			159,727	26,448
Energy Supply	2000	289,583	190,693	9,032		135,000		24,143

* Mr. Kelly was elected as Chief Operating Officer effective October 22, 2003.

** Mr. Petillo terminated his employment on August 31, 2003.

(1) The amounts in this column for 2002 represent awards earned under the Xcel Energy Executive Annual Incentive Award program. For Mr. Brunetti, Mr. Kelly, Mr. Petillo and Mr. Wilks, the amounts for 2001 include the value of 25,068, 4,449, 10,536 and 5,682 shares, respectively, of restricted common stock they received in lieu of a portion of the cash payments to which they were otherwise entitled under the Xcel Energy Executive Annual Incentive Award program. For Mr. Bonavia, the amount for 2001 includes the pre-tax value of

3,023 shares of common stock he received in lieu of a portion of the cash payment to which he was otherwise entitled under the Xcel Energy Executive Annual Incentive Award program.

(2) The amounts shown for 2001 and 2002 include reimbursements for taxes on certain personal benefits, including flexible perquisites received by the named executives. The 2000 amount for Messrs. Brunetti and Kelly also include taxes on relocation benefits of $162,745 and $55,855, respectively.

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(3) At December 31, 2002, Messrs. Brunetti, Kelly, Petillo and Wilks held shares of restricted stock. As of December 31, 2002, Mr. Brunetti held 39,083, Mr. Kelly held 4,720, Mr. Petillo held 11,177, and Mr. Wilks held 7,442 shares of restricted stock with an aggregate value of $429,913.84, $51,916.99, $122,948.39 and 81,862.04, respectively. Restricted stock vests in three equal annual installments and the holders are entitled to receive dividends at the same rate as paid on all other shares of common stock. The dividends are reinvested in additional shares of stock which is also restricted for the same periods as the underlying restricted stock on which the dividends are paid.

(4) The amounts shown for 2000 include stock option awards made to the named executives under the NSP Long Term Incentive Plan for Mr. Johnson (38,188). The balance of the options for Mr. Johnson in 2000, and all of the options for Messrs. Brunetti, Kelly, Bonavia, Petillo and Wilks for 2000 were granted under the Xcel Energy Omnibus Incentive Plan. These grants were three-year front-loaded (i.e., they represented three years worth of options) and additional options were not granted in 2001 or 2002.

(5) The amounts shown for 2001 include cash payments made under the Xcel Energy Long-term Incentive Program. NSP had no LTIP payouts in 2000. No performance cash awards under the NCE Value Creation Plan for Messrs. Brunetti, Kelly, Bonavia, Petillo and Wilks were paid during 2001 or 2000.

(6) The amounts represented in the All Other Compensation column for the year 2002 for the Named Executive Officers include the following:

Name	Company Matching 401(k) Contributions ($)	Contributions to the Non-Qualified Savings Plan ($)	Value of the remainder of insurance premiums paid by the Company under the Officer Survivor Benefit Plan ($)	Imputed Income as a result of the Life Insurance paid by the Company ($)	Earnings Accrued under Deferred Compensation Plan ($)	Bonus related to Relocation Payments ($)	Total ($)(a)
Wayne H. Brunetti	8,000	34,780	n/a	5,127	0	47,925	95,832
Richard C. Kelly	8,000	12,580	n/a	2,387	0	22,950	45,917
Gary R. Johnson	1,400	0	440	1,936	22,880	n/a	26,656
Paul J. Bonavia	8,000	0	n/a	1,278	0	n/a	9,278
James T. Petillo	8,000	5,980	n/a	1,177	0	n/a	15,157
David M. Wilks	8,000	5,980	n/a	1,490	0	12,075	27,545

(a) The total of All Other Compensation does not include an additional allocation that will be made to all participants due to the early repayment of the outstanding loans under the Employee Stock Ownership Plan.

Aggregated Option/SAR Exercises in Last Fiscal Year and FY-End Option/SAR Values

The following table indicates for each of the named executives the number and value of exercisable and unexercisable options and SARs as of December 31, 2002.

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at FY-End(#)		Value of Unexercised In-the-Money Options/ SARs at FY-End($)(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Wayne H. Brunetti			692,850	756,000		
Richard C. Kelly			224,750	228,000		
Gary R. Johnson			116,465	147,000		
Paul J. Bonavia			186,000	153,000		
James T. Petillo			112,530	126,000		

David M. Wilks	173,600	135,000

(1) Option values were calculated based on a $11.00 closing price of Xcel Energy common stock, as reported on the New York Stock Exchange at December 31, 2002.

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Long-Term Performance Plan Awards in Last Fiscal Year(1)

The following table shows information on awards granted during 2002 under our Omnibus Incentive Plan for each person in the Summary Compensation Table.

Name	Number of Shares, Units or Other Rights(2)	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans		
			Threshold($)(3)	Target($)	Maximum($)
Wayne H. Brunetti	119,566	1/1/02-12/31/04	832,031	3,328,125	6,656,250
Richard C. Kelly	30,690	1/1/02-12/31/04	213,563	854,250	1,708,500
Gary R. Johnson	15,763	1/1/02-12/31/04	109,688	438,750	877,500
Paul J. Bonavia	15,560	1/1/02-12/31/04	108,281	433,125	866,250
James T. Petillo	13,944	1/1/02-12/31/04	97,031	388,125	776,250
David M. Wilks	13,944	1/1/02-12/31/04	97,031	388,125	776,250

(1) The amounts in this table for the year 2002 are for the performance period 1/1/02-12/31/04 and represent awards made under the performance unit component described under Long-term Incentives.

(2) Each unit represents the value of one share of our common stock.

(3) If the threshold for the performance unit component of the 35th percentile is achieved, the payout could range between 25 percent and 200 percent. The amounts are based on a stock price of $27.8350, which was the average high/low price on January 2, 2002.

Pension Plan Table

The following table shows estimated combined pension benefits payable to a covered participant from the qualified and non-qualified defined benefit plans maintained by us and our subsidiaries and the Xcel Energy Supplemental Executive Retirement Plan (the SERP). The Named Executive Officers are all participants in the SERP and the qualified and non-qualified defined benefit plans sponsored by us.

Remuneration	Years of Service		
	10 years	15 years	20 or more years
200,000	55,000	82,500	110,000
225,000	61,875	92,813	123,750
250,000	68,750	103,125	137,500
275,000	75,625	113,438	151,250
300,000	82,500	123,750	165,000
350,000	96,250	144,375	192,500
400,000	110,000	165,000	220,000
450,000	123,750	185,625	247,500
500,000	137,500	206,250	275,000
600,000	165,000	247,500	330,000
700,000	192,500	288,750	385,000
800,000	220,000	330,000	440,000
900,000	247,500	371,250	495,000
1,000,000	275,000	412,500	550,000
1,100,000	302,500	453,750	605,000
1,200,000	330,000	495,000	660,000
1,300,000	357,500	536,250	715,000
1,400,000	385,000	577,500	770,000
1,500,000	412,500	618,750	825,000

	Years of Service		
Remuneration	10 years	15 years	20 or more years
1,600,000	440,000	660,000	880,000
1,700,000	467,500	701,250	935,000
1,800,000	495,000	742,500	990,000
1,900,000	522,500	783,750	1,045,000
2,000,000	550,000	825,000	1,100,000
2,100,000	577,500	866,250	1,155,000
2,200,000	605,000	907,500	1,210,000

The benefits listed in the Pension Plan Table are not subject to any deduction or offset. The compensation used to calculate the SERP benefits is base salary as of December 31 plus annual incentive. The Salary and Bonus columns of the Summary Compensation Table for 2002 reflect the covered compensation used to calculate SERP benefits.

The SERP benefit accrues ratably over 20 years and, when fully accrued, is equal to (a) 55 percent of the highest three years covered compensation of the five years preceding retirement or termination minus (b) any other qualified and non-qualified benefits. The SERP benefit is payable as an annuity for 20 years, or as a single lump-sum amount equal to the actuarial equivalent present value of the 20-year annuity. Benefits are payable at age 62, or as early as age 55, but would be reduced 5 percent for each year that the benefit commencement date precedes age 62. The approximate credited years of service under the SERP as of December 31, 2002, were as follows:

Mr. Brunetti	15 years
Mr. Kelly	35 years
Mr. Johnson	24 years
Mr. Bonavia	5 years
Mr. Petillo	6 years
Mr. Wilks	25 years

Notwithstanding any special provisions related to pension benefits described under Employment Agreements and Severance Arrangements, we have granted additional credited years of service to Mr. Brunetti for purposes of SERP accrual. The additional credited years of service (approximately seven) are included in the above table. Additionally, we have agreed to grant full accrual of SERP benefits to Mr. Brunetti at age 62 and to Mr. Bonavia at age 57 and 8 months, if they continue to be employed by us until such age.

Employment Agreements and Severance Arrangements

Wayne H. Brunetti Employment Agreement

At the time of the merger agreement, NCE and NSP also entered into a new employment agreement with Mr. Brunetti, which replaced his existing employment agreement with NCE when the Merger was completed. The initial term of the new agreement is four years, with automatic one-year extensions beginning at the end of the second year and continuing each year thereafter unless notice is given by either party that the agreement will not be extended. Under the terms of the agreement, Mr. Brunetti served as Chief Executive Officer and President and a member of our board of directors for one year following the Merger, and commencing August 18, 2001 (one year after the Merger) began serving as Chief Executive Officer, President and Chairman of our Board of Directors. Mr. Brunetti is required to perform the majority of his duties at our headquarters in Minneapolis, Minnesota, and was required to relocate the residence at which he spends the majority of his time to the Twin Cities area. His agreement also provides that if Mr. Brunetti becomes entitled to receive severance benefits, he will be forbidden from competing with us and our affiliates for two years following the termination of his employment, and from disclosing confidential information of us and our affiliates.

Under his employment agreement, Mr. Brunetti will receive the following compensation and benefits:

- a base salary not less than his base salary immediately before the Merger;
- the opportunity to earn annual and long-term incentive compensation amounts not less than he was able to earn immediately before the Merger;
- life insurance coverage and participation in a supplemental executive retirement plan; and
- the same fringe benefits as he received under his NCE employment agreement, or, if greater, as those of our next highest executive officer.

If Mr. Brunetti s employment were to be terminated by us without cause or if he were to terminate his employment for good reason, he would be entitled to receive the compensation and benefits described above as if he had remained employed for the employment period remaining under his employment agreement and then retired, at which time he would be eligible for all retiree benefits provided to our retired senior executives. In determining the level of his compensation following termination of employment, the amount of incentive compensation he would receive would be based upon the target level of incentive compensation he would have received in the year in which his termination occurred, and he would receive cash equal to the value of stock options, restricted stock and other stock-based awards he would have received instead of receiving the awards. In addition, the restrictions on his restricted stock would lapse and his stock options would have become vested. Finally, we would be obligated to make Mr. Brunetti whole for any excise tax on severance payments that he incurs.

Mr. Brunetti also had a change-of-control employment agreement with NCE. The Merger did not cause a change of control under this agreement, so it did not become effective as a result of the Merger. However, in case this agreement becomes effective because of a later change of control, Mr. Brunetti has waived his right to receive any severance benefits under the change-of-control employment agreement to the extent they would duplicate severance benefits under his employment agreement.

Paul J. Bonavia Employment Agreement

In connection with and effective upon completion of the Merger, we and Paul J. Bonavia entered into an amendment to an employment agreement between Mr. Bonavia and NCE. Except as discussed below, the original agreement expired December 14, 2000. In connection with the Merger, Mr. Bonavia s position changed from Senior Vice President, General Counsel and President of NCE s International Business Unit to President of our Energy Markets Business Unit. In the amendment, Mr. Bonavia agreed not to assert before January 6, 2003 that his duties and responsibilities had been diminished, and thus he has waived the right to claim certain benefits under the Xcel Energy Senior Executive Severance Policy relating to this change in his status prior to that date. If certain conditions were met on January 6, 2003 or within seven business days thereafter, which conditions include the termination of Mr. Bonavia s employment, Mr. Bonavia would have been entitled to severance benefits comparable to those provided to the other senior executives under the Xcel Energy Senior Executive Severance Policy. Mr. Bonavia and we have recently entered into another amendment to this agreement. As part of this amendment, Mr. Bonavia agreed to continue his employment through August 31, 2003. Mr. Bonavia also agreed not to assert that his duties and responsibilities have been diminished. In return, we agreed that if we terminate Mr. Bonavia s employment for any reason other than cause, or if Mr. Bonavia terminates his employment for any reason after August 31, 2003, then he will be entitled to severance benefits comparable to those that were provided under the Xcel Energy Senior Executive Severance Policy prior to its expiration as described below.

Severance Policy

NSP and NCE each adopted a 1999 senior executive severance policy in March 1999. These policies were combined into a single Xcel Energy Senior Executive Severance Policy, which terminated on August 18, 2003 on its scheduled termination date. All of our executive officers other than Mr. Brunetti participated in the policy until its termination.

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Under the policy, a participant whose employment was terminated at any time before August 18, 2003, the third anniversary of the Merger, received severance benefits unless:

- the employer terminated the participant for cause;
- the termination was because of the participant s death, disability or retirement;
- the division or subsidiary in which the participant worked was sold and the buyer agreed to continue the participant s employment with specified protections for the participant; or
- the participant terminated voluntarily without good reason.

To receive the severance benefits, the participant must have also signed an agreement releasing all claims against the employer and its affiliates, and agreeing not to compete with the employer and its affiliates and not to solicit their employees and customers.

The severance benefits for executive officers under the policy included the following:

- a cash payment equal to 2.5 times the participant s annual base salary, annual bonus and annualized long-term incentive compensation, prorated incentive compensation for the year of termination and perquisite allowance;
- a cash payment equal to the additional amounts that would have been credited to the executive under pension and retirement savings plans, if the participant had remained employed for another 2.5 years;
- continued welfare benefits for 2.5 years;
- financial planning benefit for two years, and outplacement services costing not more than $30,000; and
- an additional cash payment to make the participant whole for any excise tax on excess severance payments that he or she may incur, with certain limitations specified in the policies.

Some of the executive officers of NCE who participated in the severance policy also had change-of-control employment agreements with NCE. The Merger was not considered a change of control under these agreements, so they did not become effective as a result of the Merger.

Our former President Energy Delivery, James T. Petillo, terminated his employment on August 31, 2003. In connection with the termination of his employment, Mr. Petillo entered into an agreement with us under which he waived claims to certain benefits he would have received under our senior executive severance policy had he terminated his employment prior to the expiration of the policy. Mr. Petillo received a cash payment of $2 million, continued welfare benefits for 2.5 years, financial planning benefits for two years and outplacement services costing no more than $30,000. The agreement with Mr. Petillo also contains non-competition, non-solicitation and non-disparagement clauses.

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Securities Authorized for Issuance under Equity Compensation Plans

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders(1)(2)	16,981,107	$26.29	8,391,313
Equity compensation plans not approved by security holders(3)	N/A	N/A	(2)

(1)

Plan	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
PSCo Omnibus Incentive Plan	299,351	$21.82	
Xcel Energy Inc. Omnibus Incentive Plan	7,168,634	$26.56	7,004,568
NRG Long-Term Incentive Compensation Plan	2,766,551	$29.61	
NCE Omnibus Incentive Plan	3,235,039	$26.36	
NSP Executive Long-Term Incentive Award Stock Plan	3,511,532	$23.44	
Xcel Energy Inc. Executive Annual Incentive Award Plan			1,386,745

(2) On March 28, 2003, the Governance, Compensation and Nominating Committee of our board of directors granted restricted stock units and performance shares under the Xcel Energy Omnibus Incentive Plan approved by the shareholders in 2000. No stock options have been granted in 2003. Restrictions on the restricted stock units will lapse, but not before one year from the date of grant, after 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. If the TSR target and other criteria relating to our common equity ratio is not met within four years, the grant will be forfeited. 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.

(3) We have a Stock Equivalent Plan for Non-Employee Directors to more closely align directors interests with those of our shareholders. Under this Stock Equivalent Plan, directors may receive an annual award of stock equivalent units with each unit having a value equal to one share of Xcel Energy common stock. Stock equivalent units do not entitle a director to vote and are only payable as a distribution of whole shares of the Company s common stock upon a director s termination of service. The stock equivalent units fluctuate in value as the value of Xcel Energy common stock fluctuates. The number of stock equivalent units that may be awarded under this Stock Equivalent Plan is not limited. The shares of Xcel Energy common stock to be used for distribution under this Stock Equivalent Plan are purchased on the open market.

DESCRIPTION OF OTHER INDEBTEDNESS

In addition to the original senior notes, we currently have other unsecured indebtedness in the amount of approximately $1.025 billion outstanding that rank pari passu with the original senior notes and will rank pari passu with the exchange senior notes, when issued. Furthermore, on September 30, 2003, our subsidiaries had

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approximately $12.1 billion of indebtedness and other liabilities, all of which is effectively senior to the original senior notes and will be effectively senior to the exchange senior notes, when issued, and some of which is secured by the assets of the respective subsidiaries.

DESCRIPTION OF THE EXCHANGE SENIOR NOTES

The description below contains summaries of selected provisions of the indenture under which the exchange senior notes will be issued. The following description of provisions of the exchange senior notes is not complete and is subject to, and qualified in its entirety by reference to, the exchange senior notes and the indenture. For purposes of this Description of the Exchange Senior Notes, any references to Xcel Energy, we, our, us or the company refer to Xcel Energy Inc. and not its subsidiaries.

General

We will issue the exchange senior notes as a series of securities under the Indenture dated December 1, 2000 between us and Wells Fargo Bank Minnesota, National Association, as trustee (the Trustee). We refer to this indenture, as supplemented and to be supplemented by various supplemental indentures, including one or more supplemental indentures relating to the exchange senior notes being offered by this prospectus, as the Indenture. We refer to the debt securities issued under the Indenture, whether previously issued or to be issued in the future, including the exchange senior notes being offered by this prospectus, as the debt securities.

The exchange senior notes will bear interest at the annual rate stated on the cover page from the date of the last periodic payment of interest on the original senior notes, or, if no interest has been paid, from June 24, 2003 at a rate of 3.40 percent per year and will mature on July 1, 2008.

Form and Denomination

We will issue the exchange senior notes in fully registered form, without coupons, in denominations of $1,000 principal amount and whole multiples of $1,000. The exchange senior notes will be represented by one or more global securities registered in the name of The Depository Trust Company (DTC), as Depository (the Depository), or its nominee and will be available only in book-entry form. See Book-Entry System. We will pay principal and interest in immediately available funds to the registered holder, which will be DTC or its nominee.

Ranking

The exchange senior notes will be our unsecured and unsubordinated obligations. The exchange senior notes will rank on a parity in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. However, the exchange senior notes will be subordinated to any of our secured indebtedness, as to the assets securing such indebtedness. As of September 30, 2003, we had no secured indebtedness and had unsecured and unsubordinated indebtedness of $1.025 billion outstanding.

In addition, the exchange senior notes are effectively subordinated to all existing and future liabilities of our subsidiaries. We are a holding company and conduct business through our various subsidiaries. As a result, our cash flow and consequent ability to meet our debt obligations primarily depend on the earnings of our subsidiaries, and on dividends and other payments from our subsidiaries. Under certain circumstances, contractual and legal restrictions, as well as the financial condition and operating requirements of our subsidiaries, could limit our ability to obtain cash from our subsidiaries for the purpose of meeting debt service obligations, including the payment of principal and interest on the exchange senior notes. Any rights to receive assets of any subsidiary upon its liquidation or reorganization and the consequent right of the holders of the exchange senior notes to participate in those assets will be subject to the claims of that subsidiary s creditors, including trade creditors, except to the extent that we are recognized as a creditor of that subsidiary, in which case its claims would still be subordinate to any security interests in the assets of that subsidiary. As of September 30, 2003, our subsidiaries had aggregate liabilities of $12.1 billion. This amount does not include indebtedness and other liabilities of NRG, which was deconsolidated on our financial statements following its bankruptcy filing.

Payment and Paying Agents

The entire principal amount of the exchange senior notes will mature and become due and payable, together with any accrued and unpaid interest, on July 1, 2008. Each exchange senior note will bear interest from the date of the last periodic payment of interest on the original senior notes, or, if no interest has been paid, from June 24, 2003, at the rate of 3.40 percent per year. The interest will be payable semi-annually on January 1 and July 1 of each year, commencing January 1, 2004. The interest will be paid to the person in whose name the exchange senior note is registered at the close of business on the December 15 or June 15 immediately preceding the January 1 or July 1. We will compute the interest on the basis of a 360-day year comprised of twelve 30-day months.

Principal, interest and premium, if any, on the exchange senior notes will be paid in the manner described under Book-Entry System.

All monies paid by us to a paying agent for the payment of principal, interest or premium, if any, on any exchange senior notes which remained unclaimed at the end of two years after that principal, interest or premium has become due and payable will be repaid to us and the holder of that exchange senior note will thereafter look only to us for payment of that principal, interest or premium.

Redemption Provisions

There are no provisions in the Indenture or the exchange senior notes that require us to redeem, or permit the holders to cause a redemption of, the exchange senior notes or that otherwise protect the holders in the event that we incur substantial additional indebtedness, whether or not in connection with a change in control of our company. However, any change in control transaction that involves the incurrence of substantial additional long-term indebtedness by us in such a transaction could require approval of state regulatory authorities and, possibly, of federal utility regulatory authorities. Management believes that such approvals would be unlikely in any transaction that would result in our company, or a successor to our company, having a highly leveraged capital structure.

We may redeem the exchange senior notes at any time, in whole or in part, at a redemption price equal to the greater of (1) the principal amount being redeemed or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the exchange senior notes being redeemed, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Yield plus 25 basis points, plus in each case accrued interest to the redemption date.

Treasury Yield means, for any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

Comparable Treasury Issue means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of the exchange senior notes that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the exchange senior notes.

Independent Investment Banker means UBS Securities LLC or its successor or, if such firm or its successor is unwilling or unable to select the Comparable Treasury Issue, one of the remaining Reference Treasury Dealers appointed by the Trustee after consultation with us.

Comparable Treasury Price means, for any redemption date, (1) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) on the third business day preceding the redemption date, as set forth in the daily statistical release (or any successor release) published by the Federal Reserve Bank of New York and designated Composite 3:30 p.m.

Quotations for U.S. Government Securities or (2) if that release (or any successor release) is not published or does not contain those prices on that business day, (A) the average of the Reference Treasury Dealer Quotations for the redemption date, after excluding the highest and lowest Reference Treasury Dealer Quotations for the redemption date, or (B) if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all of the Quotations.

Reference Treasury Dealer Quotations means, for each Reference Treasury Dealer and any redemption date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by the Reference Treasury Dealer at 5:00 p.m. on the third business day preceding the redemption date.

Reference Treasury Dealer means (1) each of Credit Suisse First Boston LLC, McDonald Investments Inc., UBS Securities LLC and any other primary U.S. Government Securities dealer in the United States (a Primary Treasury Dealer) designated by, and not affiliated with, Credit Suisse First Boston LLC, McDonald Investments Inc., UBS Securities LLC and their respective successors, provided, however, that if any of the foregoing or any of their designees ceases to be a Primary Treasury Dealer, we will appoint another Primary Treasury Dealer as a substitute and (2) any other Primary Treasury Dealer selected by us.

Notice of redemption will be given by mail not less than 30 days but not more than 60 days prior to the date fixed for redemption to the holders of the exchange senior notes to be redeemed. If we elect to redeem less than all the exchange senior notes and the exchange senior notes are at the time represented by one or more global securities, then the Depository will select by lot the particular interest to be redeemed. If we elect to redeem less than all of the exchange senior notes, and the exchange senior notes are not represented by a global security, then the Trustee will select the particular exchange senior notes to be redeemed in a manner it deems appropriate and fair.

The exchange senior notes do not provide for any sinking fund.

Events of Default

The following are events of default under the Indenture:

- default in the payment of principal and premium, if any, on any debt security issued under the Indenture when due and payable and continuance of that default for 5 days;

- default in the payment of interest on any debt security when due which continues for 30 days;

- default in the performance or breach of our other covenants or warranties in the Indenture and the continuation of that default or breach for 90 days after written notice to us by the Trustee or to us and the Trustee by holders of at least 33 percent in principal amount of the outstanding debt securities as provided in the Indenture; and

- specified events of bankruptcy, insolvency or reorganization of our company.

Acceleration of Maturity. If an event of default occurs and is continuing, either the Trustee or the holders of a majority in principal amount of the outstanding debt securities may declare the principal amount of all debt securities to be due and payable immediately. At any time after an acceleration of the debt securities has been declared, but before a judgment or decree of the immediate payment of the principal amount of the debt securities has been obtained, if we pay or deposit with the Trustee a sum sufficient to pay all matured installments of interest and the principal and any premium which has become due otherwise than by acceleration and all defaults have been cured or waived, then that payment or deposit will cause an automatic rescission and annulment of the acceleration of the debt securities.

Indemnification of Trustee. The Trustee generally will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders unless the holders have offered reasonable security or indemnity to the Trustee.

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Right to Direct Proceedings. The holders of a majority in principal amount of the outstanding debt securities generally will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or of exercising any trust or power conferred on the Trustee, relating to the debt securities.

Limitation on Rights to Institute Proceedings. No holder of the debt securities will have any right to institute any proceeding with respect to the Indenture, or for the appointment of a receiver or a trustee, or for any other remedy under the Indenture, unless:

- the holder has previously given the Trustee written notice of a continuing event of default with respect to the debt securities;
- the holders of a majority in principal amount of the outstanding debt securities affected by such event of default have made written request, and the holder or holders have offered reasonable indemnity, to the Trustee, to institute the proceeding as trustee; and
- the Trustee has failed to institute the proceeding within 60 days after the notice, request and offer.

No Impairment of Right to Receive Payment. Notwithstanding any other provision of the Indenture, the holder of any debt security will have the absolute and unconditional right to receive payment of the principal, premium, if any, and interest on that debt security when due, and to institute suit for enforcement of that payment. This right may not be impaired without the consent of the holder.

Notice of Default. The Trustee is required to give the holders notice of the occurrence of a default within 90 days of the default, unless the default is cured or waived. Except in the case of a payment default on the debt securities, or a default in the payment of any sinking or purchase fund installments, the Trustee may withhold the notice if its board of directors or trustees, executive committee or a trust committee of directors or trustees or responsible officers determines in good faith that it is in the interest of holders to do so. We are required to deliver to the Trustee each year a certificate as to whether or not we are in compliance with the conditions and covenants under the Indenture.

Waiver. The holders of not less than a majority in aggregate principal amount of the outstanding debt securities may, on behalf of the holders of all debt securities, waive any default or event of default, except a default in the payment of the principal, premium, if any, or interest on the debt securities.

Registration, Transfer and Exchange

The exchange senior notes may be exchanged for other exchange senior notes of the same series of any authorized denominations and of a like aggregate principal amount and kind.

The exchange senior notes may be presented for registration of transfer (duly endorsed or accompanied by a duly executed written instrument of transfer), at the office of the Trustee maintained for such purpose with respect to the exchange senior notes, without service charge and upon payment of any taxes and other governmental charges as described in the Indenture. Such transfer or exchange will be effected upon being satisfied with the documents of title and indemnity of the person making the request.

In the event of any redemption of the exchange senior notes, the Trustee will not be required to exchange or register a transfer of any exchange senior note selected, called or being called for redemption except, in the case of any exchange senior note to be redeemed in part, the portion thereof not to be so redeemed.

Modification

We and the Trustee may modify and amend the Indenture from time to time. Depending upon the type of amendment, we may not need the consent or approval of any of the holders of the debt securities, including the exchange senior notes offered by this prospectus, or we may need either the consent or approval of the holders of a majority in principal amount of the outstanding debt securities affected by the proposed amendment or the consent or the approval of each holder affected by the proposed amendment.

We will not need the consent of the holders for the following types of amendments:

- curing any ambiguity, or curing, correcting or supplementing any defective or inconsistent provision or supplying an omission arising under the Indenture;
- changing or eliminating any of the provisions of the Indenture, provided that this change or elimination is to become effective only when:
  - there is no outstanding debt security created prior to the execution of the supplemental indenture which will receive the benefit of this provision; or
  - this change or elimination is applicable only to debt securities issued after the date this change or elimination becomes effective;
- establishing the form of the debt securities or establishing or reflecting any terms of any debt security as provided in the Indenture;
- evidencing our successor corporation and the assumption by our successor of our covenants in the Indenture and in the debt securities;
- granting or conferring upon the Trustee any additional rights, remedies, powers or authority for the benefit of the holders of the debt securities;
- permitting the Trustee to comply with any duties imposed upon it by law;
- specifying further the duties and responsibilities of the Trustee, any authenticating agent and any paying agent and defining further the relationships among the Trustee, authenticating agent and paying agent;
- adding to our covenants for the benefit of the holders or surrendering a right given to us in the Indenture;
- adding security for the debt securities; or
- making any change that is not prejudicial to the Trustee or the holders of the debt securities that is not stated in the Indenture.

We will need the consent of the holders of each outstanding debt security affected by a proposed amendment if the amendment would cause any of the following to occur:

- a change in the maturity date or rate of any debt security;
- a change in date on which any debt security may be redeemed or repaid at the option of the holder;
- a reduction in the principal amount of any debt security or the premium payable on any debt security;
- a change in the currency of any payment of principal, premium or interest on any debt security;
- an impairment of the right of a holder to institute suit for the enforcement of any payment relating to any debt security;
- a reduction in the percentage of outstanding debt securities necessary to consent to the modification or amendment of the Indenture; or
- a modification of these requirements or a reduction to less than a majority of the percentage of outstanding debt securities necessary to waive events of default under the Indenture.

Defeasance and Discharge

We may be discharged from all obligations relating to the debt securities and the Indenture (except for specified obligations such as obligations to register the transfer or exchange of debt securities, replace stolen, lost or mutilated debt securities and maintain paying agencies) if we irrevocably deposit with the Trustee, in trust for the benefit of holders of debt securities, money or United States government obligations, or any

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combination thereof, sufficient to make all payments of principal, premium and interest on the debt securities on the dates those payments are due. If we discharge those obligations, we must deliver to the Trustee an opinion of counsel that the holders of the debt securities will not recognize income, gain or loss for federal income tax purposes as a result of such defeasance or discharge of the Indenture. Upon any discharge of our obligations as described above, we will be deemed to have paid and discharged our entire indebtedness represented by the debt securities and our obligations under the debt securities.

Consolidation, Merger and Sale of Assets; No Financial Covenants

We will not consolidate with or merge into any other corporation or sell, or otherwise dispose all or substantially all our assets unless (1) the successor or transferee corporation assumes by supplemental indenture our obligations to pay the principal and premium and interest on debt securities issued under the Indenture and our obligation to perform every covenant of the Indenture to be performed or observed by us and (2) we or the successor or transferee corporation, as applicable, are not, immediately following such consolidation, merger, sale or disposition, in default in the performance of any such covenant. Upon any consolidation, merger, sale or transfer or disposition of all or substantially all of the assets of our company, the successor or transferee corporation will succeed to, and be substituted for, and may exercise every right and power of, our company under the Indenture with the same effect as if the successor corporation had been named as us in the Indenture and we will be released from all obligations under the Indenture. Regardless of whether a sale or transfer of assets might otherwise be considered a sale of all or substantially all of our assets, the Indenture also specifically permits any sale, transfer or conveyance of our non-utility subsidiaries if, following such sale or transfer, the exchange senior notes offered by this prospectus are rated by Standard & Poor s and Moody s at least as high as the ratings accorded the exchange senior notes immediately prior to the sale, transfer or disposition.

The Indenture does not contain any financial or other similar restrictive covenants. The Indenture does not contain any provisions restricting us from incurring additional indebtedness secured by some or all of our assets. However, our ability to issue secured debt at the holding company level currently is severely limited due to regulatory constraints.

Resignation or Removal of Trustee

The Trustee may resign at any time by notifying us in writing and specifying the day that the resignation is to take effect. The resignation will not take effect, however, until the later of the appointment of a successor trustee and the day the resignation is to take effect.

The holders of a majority in principal amount of the outstanding debt securities may remove the Trustee at any time. In addition, so long as no event of default or event which, with the giving of notice or lapse of time or both, would become an event of default has occurred and is continuing, we may remove the Trustee upon (1) notice to the holder of each security outstanding under the Indenture and (2) upon written notice to the Trustee.

Concerning the Trustee

Wells Fargo Bank Minnesota, National Association is the Trustee. We maintain banking relationships with the Trustee in the ordinary course of business. The Trustee also acts as trustee for certain debt securities of our subsidiaries.

Governing Law

The Indenture and the exchange senior notes are governed by, and construed in accordance with, the laws of the State of Minnesota.

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BOOK-ENTRY SYSTEM

General

Except as set forth below, the exchange senior notes will initially be issued in the form of one or more global senior notes (each, a new global senior note). Each new global senior note will be deposited on the date of the closing of the exchange of the original senior notes for the exchange senior notes with, or on behalf of, DTC and will be registered in the name of DTC or its nominee. Investors may hold their beneficial interests in a new global senior note directly through DTC or indirectly through organizations which are participants in the DTC system.

Unless and until they are exchanged in whole or in part for certificated senior notes, the new global senior notes may not be transferred except as a whole by DTC or its nominee.

DTC has advised us as follows: DTC is a limited-purpose trust company organized under the laws of the State of New York, a banking organization within the meaning of New York banking law, a member of the Federal Reserve System, a clearing corporation within the meaning of the New York Uniform Commercial Code, and a clearing agency registered pursuant to the provisions of Section 17A of the Exchange Act. DTC holds and provides asset servicing for over 2 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 85 countries that DTC s participants (Direct Participants) deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation (DTCC). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Government Securities Clearing Corporation, MBS Clearing Corporation, and Emerging Markets Clearing Corporation, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly. DTC has Standard & Poor s highest rating: AAA. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Upon the issuance of the new global senior notes, DTC or its custodian will credit, on its internal system, the respective principal amounts of the exchange senior notes represented by the new global senior notes to the accounts of persons who have accounts with DTC. Ownership of beneficial interests in the new global senior notes will be limited to persons who have accounts with DTC or persons who hold interests through the persons who have accounts with DTC. Persons who have accounts with DTC are referred to as participants. Ownership of beneficial interests in the new global senior notes will be shown on, and the transfer of that ownership will be effected only through, records maintained by DTC or its nominee, with respect to interests of participants, and the records of participants, with respect to interests of persons other than participants.

As long as DTC or its nominee is the registered owner or holder of the new global senior notes, DTC or the nominee, as the case may be, will be considered the sole record owner or holder of the exchange senior notes represented by the new global senior notes for all purposes under the Indenture and the exchange senior notes. No beneficial owners of an interest in the new global senior notes will be able to transfer that interest except according to DTC s applicable procedures, in addition to those provided for under the Indenture. Owners of beneficial interests in the new global senior notes will not:

- be entitled to have the exchange senior notes represented by the new global senior notes registered in their names, receive or be entitled to receive physical delivery of certificated senior notes in definitive form; and

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be considered to be the owners or holders of any exchange senior notes under the new global senior notes.

Accordingly, each person owning a beneficial interest in new global senior notes must rely on the procedures of DTC and, if a person is not a participant, on the procedures of the participant through which that person owns its interests, to exercise any right of a holder of exchange senior notes under the new global senior notes. We understand that under existing industry practice, if an owner of a beneficial interest in the new global senior notes desires to take any action that DTC, as the holder of the new global senior notes, is entitled to take, DTC would authorize the participants to take that action, and that the participants would authorize beneficial owners owning through the participants to take that action or would otherwise act upon the instructions of beneficial owners owning through them.

Payments of the principal of, premium, if any, and interest on the exchange senior notes represented by the new global senior notes will be made by us to the Trustee and from the Trustee to DTC or its nominee, as the case may be, as the registered owner of the new global senior notes. Neither we, the Trustee, nor any paying agent will have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in the new global senior notes or for maintaining, supervising or reviewing any records relating to the beneficial ownership interests.

We expect that DTC or its nominee, upon receipt of any payment of principal of, premium, if any, or interest on the new global senior notes will credit participants accounts with payments in amounts proportionate to their respective beneficial ownership interests in the principal amount of the new global senior notes, as shown on the records of DTC or its nominee. We also expect that payments by participants to owners of beneficial interests in the new global senior notes held through these participants will be governed by standing instructions and customary practices, as is now the case with securities held for the accounts of customers registered in the names of nominees for these customers. These payments will be the responsibility of these participants.

Transfer between participants in DTC will be effected in the ordinary way in accordance with DTC rules. If a holder requires physical delivery of senior notes in certificated form for any reason, including to sell senior notes to persons in states which require the delivery of the senior notes or to pledge the senior notes, a holder must transfer its interest in the new global senior notes in accordance with the normal procedures of DTC and the procedures set forth in the Indenture.

Unless and until they are exchanged in whole or in part for certificated exchange senior notes in definitive form, the new global senior notes may not be transferred except as a whole by DTC to a nominee of DTC or by a nominee of DTC to DTC or another nominee of DTC.

DTC has advised us that DTC will take any action permitted to be taken by a holder of senior notes, including the presentation of senior notes for exchange as described below, only at the direction of one or more participants to whose account the DTC interests in the new global senior notes are credited. Further, DTC will take any action permitted to be taken by a holder of senior notes only in respect of that portion of the aggregate principal amount of senior notes as to which the participant or participants has or have given that direction.

Although DTC has agreed to these procedures in order to facilitate transfers of interests in the new global senior notes among participants of DTC, it is under no obligation to perform these procedures, and may discontinue them at any time. Neither we nor the trustee will have any responsibility for the performance by DTC or its participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Subject to specified conditions, any person having a beneficial interest in the new global senior notes may, upon request to the trustee, exchange the beneficial interest for exchange senior notes in the form of certificated senior notes. Upon any issuance of certificated senior notes, the trustee is required to register the certificated senior notes in the name of, and cause the same to be delivered to, the person or persons, or the nominee of these persons. In addition, if DTC is at any time unwilling or unable to continue as a depositary for

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the new global senior notes, and a successor depositary is not appointed by us within 120 days, we will issue certificated senior notes in exchange for the new global senior notes.

EXCHANGE OFFER AND REGISTRATION RIGHTS

As part of the sale of the original senior notes, under a registration rights agreement, dated as of June 24, 2003, we agreed with the initial purchasers in the offering of the original senior notes, for the benefit of the holders of the original senior notes, to file with the SEC an exchange offer registration statement (an Exchange Offer Registration Statement) for the purpose of offering exchange senior notes in exchange for original senior notes (a Registered Exchange Offer) or, if applicable, a shelf registration statement (as defined below).

Shelf Resale Registration Statement

If:

- a change in law or in applicable interpretations of the staff of the SEC do not permit us to effect such a Registered Exchange Offer;
- any holder of an original senior note is not eligible to participate in the Registered Exchange Offer;
- for any other reason the Registered Exchange Offer is not consummated within 210 days after the date of issue of the original senior notes;
- an initial purchaser so requests with respect to original senior notes not eligible to be exchanged for exchange senior notes in the Registered Exchange Officer; or
- any initial purchaser who participates in the Registered Exchange Offer does not receive freely tradeable exchange senior notes in the Registered Exchange Offer;

we will, at our cost,

- as promptly as practicable, but in no event more than 120 days after becoming required to do so, file a registration statement under the Securities Act covering continuous resales of the original senior notes or the exchange senior notes, as the case may be (Shelf Registration Statement);
- use our best efforts to cause the Shelf Registration Statement to be declared effective under the Securities Act; and
- use our best efforts to keep the Shelf Registration Statement effective until the earlier of (a) the time when the original senior notes covered by the Shelf Registration Statement can be sold pursuant to Rule 144 under the Securities Act without any limitations thereunder and (b) two years from the issuance of the original senior notes.

We will, in the event a Shelf Registration Statement is filed, among other things, provide to each holder for whom the Shelf Registration Statement was filed copies of the prospectus which is a part of the Shelf Registration Statement, notify each such holder when the Shelf Registration Statement has become effective and take other actions as are required to permit unrestricted resales of the original senior notes or the exchange senior notes, as the case may be. A holder that sells original senior notes issued pursuant to the Shelf Registration Statement generally will be required to be named as a selling security holder in the related prospectus and to deliver a prospectus to purchasers, will be subject to applicable civil liability provisions under the Securities Act in connection with sales of that kind and will be bound by the provisions of the registration rights agreement that are applicable to that holder (including certain indemnification obligations).

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Liquidated Damages

We will pay liquidated damages if:

(1) the Exchange Offer Registration Statement or the Shelf Registration Statement is not declared effective by the SEC on or prior to the applicable effectiveness deadline specified in the registration rights agreement;

(2) after either the Exchange Offer Registration Statement or the Shelf Registration Statement is declared effective, such registration statement thereafter ceases to be effective or usable (subject to certain exceptions) in connection with resales of original senior notes or exchange senior notes, as the case may be, as provided in and during the periods specified in the registration rights agreement (each such event referred to in clauses (1) and (2), a Registration Default).

Liquidated damages will be incurred from and including the date on which any such Registration Default shall occur to and including the first week in which all Registration Defaults have been cured in an amount equal to $0.10 per week per $1,000 principal amount of original senior notes or exchange senior notes.

We will pay liquidated damages to the holders of global notes by wire transfer of immediately available funds or by federal funds check and to holders of certificated notes by wire transfer to the accounts specified by them or by mailing checks to their registered address if no such accounts have been specified. No liquidated damages will be paid for any week beginning after all Registration Defaults have been cured.

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MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following is a discussion of the material U.S. federal income tax consequences of the exchange of original senior notes for exchange senior notes. This summary is based on the Internal Revenue Code of 1986, as amended, Treasury regulations, administrative pronouncements and judicial decisions, all as in effect on the date of this prospectus and all subject to change or differing interpretations, possibly with retroactive effect. This discussion is limited to holders that purchased the original senior notes upon their original issuance and that hold the original senior notes, and will hold the exchange senior notes, as capital assets within the meaning of Section 1221 of the Internal Revenue Code. This discussion does not address all of the tax consequences that may be relevant to a holder in light of the holder s particular circumstances or to holders subject to special rules, such as financial institutions, tax-exempt entities, holders whose functional currency is not the U.S. dollar, insurance companies, dealers in securities or foreign currencies, persons holding notes as part of a hedge, straddle or other integrated transaction, or persons who have ceased to be United States citizens or to be taxed as resident aliens. You should consult with your own tax advisor about the application of the U.S. federal income tax laws to your particular situation as well as any consequences of the exchange under the tax laws of any state, local or foreign jurisdiction.

Your acceptance of the exchange offer and your exchange of original senior notes for exchange senior notes will not be taxable for U.S. federal income tax purposes because the exchange senior notes will not be considered to differ materially in kind or extent from the original senior notes. Rather, the exchange senior notes you receive will be treated as a continuation of your investment in the original senior notes. Accordingly, you will not recognize gain or loss upon the exchange of original senior notes for exchange senior notes pursuant to the exchange offer, your tax basis in the exchange senior notes will be the same as your adjusted tax basis in the original senior notes immediately before the exchange, and your holding period for the exchange senior notes will include the holding period for the original senior notes exchanged therefor. There will be no U.S. federal income tax consequences to holders that do not exchange their original senior notes pursuant to the exchange offer.

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PLAN OF DISTRIBUTION

Based on interpretations by the staff of the SEC in no-action letters issued to third parties, we believe that you may freely transfer exchange senior notes issued in the exchange offer if:

- you acquire the exchange senior notes in the ordinary course of your business; and
- you are not engaged in, and do not intend to engage in, and have no arrangement or understanding with any person to participate in, a distribution of exchange senior notes.

We believe that you may not transfer exchange senior notes issued in the exchange offer in exchange for the original senior notes if you are:

- our affiliate, within the meaning of Rule 405 under the Securities Act;
- a broker-dealer that acquired original senior notes directly from us; or
- a broker-dealer that acquired original senior notes as a result of market-making activities or other trading activities without compliance with the registration and prospectus delivery provisions of the Securities Act.

If you wish to exchange your original senior notes for exchange senior notes in the exchange offer, you will be required to make representations to us as described under the caption The Exchange Offer Procedures for Tendering and in the letter of transmittal.

Each broker-dealer that receives exchange senior notes for its own account under the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange senior notes. Broker-dealers may use this prospectus, as it may be amended or supplemented from time to time, for resales of exchange senior notes received in exchange for original senior notes where the original senior notes were acquired as a result of market-making activities or other trading activities. We have agreed that, starting on the date of completion of the exchange offer and ending on the close of business 210 days after such date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale.

We will not receive any proceeds from any sale of exchange senior notes by broker-dealers. Broker-dealers may sell exchange senior notes received for their own account under the exchange offer in one or more transactions:

- in the over-the-counter market;
- in negotiated transactions;
- through the writing of options on the exchange senior notes; or
- a combination of such methods of resale.

The prices at which these sales occur may be:

- at market prices prevailing at the time of resale;
- at prices related to such prevailing market prices; or
- at negotiated prices.

Broker-dealers may make any such resale directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer and/or the purchasers of any such exchange senior notes. Any broker-dealer that receives exchange senior notes for its own account under the exchange offer and any broker or dealer that participates in a distribution of such exchange senior notes may be deemed to be an underwriter within the meaning of the Securities Act. Any profit on any such resale of exchange senior notes and any commission or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal

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states that, by acknowledging that it will deliver, and by delivering, a prospectus, a broker-dealer will not admit that it is an underwriter within the meaning of the Securities Act.

Furthermore, any broker-dealer that acquired any of its original senior notes directly from us:

may not rely on the applicable interpretation of the staff of the SEC s position contained in Exxon Capital Holdings Corp., SEC no-action letter (available April 13, 1988), Morgan, Stanley & Co. Inc., SEC no-action letter (available June 5, 1991) and Shearman & Sterling, SEC no-action letter (available July 2, 1983); and

must also be named as a selling senior noteholder in connection with the registration and prospectus delivery requirements of the Securities Act relating to any resale transaction.

For a period of 210 days from the date of completion of this exchange offer, we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. We have agreed to pay all expenses incident to the exchange offer other than commissions or concessions of any broker-dealers and will indemnify the holders of the original senior notes (including any broker-dealers) against some liabilities, including liabilities under the Securities Act.

LEGAL OPINIONS

Legal opinions relating to the exchange senior notes will be rendered by our counsel, Gary R. Johnson, 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota. Gary R. Johnson is our Vice President and General Counsel and is the beneficial owner, as of August 31, 2003, of 129,706 shares of our common stock.

EXPERTS

The consolidated financial statements of Xcel Energy Inc. (the Company) and its consolidated subsidiaries, except NRG Energy, Inc. and subsidiaries, as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, included in this prospectus and the related financial statement schedules included elsewhere in the registration statement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein (which report expresses an unqualified opinion and is based in part on the report of other auditors and includes emphasis of a matter paragraphs relating to the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* on January 1, 2001, the adoption of 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 implications to Xcel Energy Inc. related to credit and liquidity constraints, various defaults under credit arrangements, and a Chapter 11 bankruptcy protection filing at NRG Energy, Inc.); and have been so included in reliance upon the report of such firm given their authority as experts in accounting and auditing.

The consolidated financial statements of NRG Energy, Inc. and subsidiaries, not presented separately herein, have been audited by PricewaterhouseCoopers LLP, independent accountants, as stated in their report included herein, which report contains an explanatory paragraph relating to the ability of NRG Energy, Inc. to continue as a going concern as described in Note 1 to the consolidated financial statements of NRG Energy, Inc. as of December 31, 2002 and 2001 and for each of three years in the period ended December 31, 2002, and relating to the adoption of Statements of Financial Accounting Standard No s. 133, 142 and 144; and is given on the authority of PricewaterhouseCoopers LLP as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, 450 Fifth Street, N.W., Washington, D.C. 20549, a Registration Statement on Form S-4 under the Securities Act relating to the offering. As permitted by the rules and regulations of the SEC, this prospectus does not contain all the information contained in the registration statement. For further information about us and the offering, you can read the registration statement and the exhibits and financial schedules filed with the registration statement. The statements contained in this prospectus about the contents of any contract or other document are not necessarily complete. You can read a copy of each contract or other document filed as an exhibit to the registration statement.

We are currently subject to the information reporting requirements of the Exchange Act and we file annual, quarterly and special reports and other information with the SEC. Our SEC filings are available free of charge to the public over the Internet at the SEC s web site at http://www.sec.gov. Our SEC filings are also available at our web site at http://www.xcelenergy.com. You may also read and copy any document we file at the SEC s public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

You may request a copy of these filings at no cost, by writing or telephoning us at the following address:

Corporate Secretary
Xcel Energy Inc.
800 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500

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INDEPENDENT AUDITORS REPORT

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of operations, common stockholders equity and other comprehensive income and cash flows for the three years ended December 31, 2002. Our audit also included the financial statement schedule listed in the Index. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We did not audit the consolidated balance sheet of NRG Energy, Inc. (a wholly owned subsidiary of Xcel Energy Inc.) for the years ended December 31, 2002 and 2001, or the consolidated statements of operations, stockholder s (deficit)/equity and cash flows for the three years ended December 31, 2002 included in the consolidated financial statements of the Company, which statements reflect total assets and revenues of 40% and 24% for 2002, respectively, and total assets and revenues of 45% and 21% for 2001, respectively, and revenues of 20% for 2000, of the related consolidated totals. Those statements were audited by other auditors whose report has been furnished to us (which as to 2002 expresses an unqualified opinion and includes an explanatory paragraph describing conditions that raise substantial doubt about NRG Energy, Inc. s ability to continue as a going concern and emphasis of a matter paragraphs related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible* Assets and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002 and the adoption of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* on January 1, 2001), and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. for the periods described above, is based solely on the report of the other auditors.

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

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2002 and 2001 and the results of their operations and their cash flows for each of the three years ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

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

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

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

/s/ DELOITTE & TOUCHE LLP
Deloitte & Touche LLP
Minneapolis, Minnesota
March 28, 2003

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REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder s (deficit)/equity present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

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

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

/s/ PRICEWATERHOUSECOOPERS LLP
PricewaterhouseCoopers LLP
Minneapolis, Minnesota
March 28, 2003

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Thousands of Dollars, Except Per Share Data)

	Year ended Dec. 31,		
	2002	**2001**	**2000**
Operating revenues:			
Electric utility	$ 5,435,377	$ 6,394,737	$5,674,485
Natural gas utility	1,397,800	2,052,651	1,468,880
Electric and natural gas trading margin	8,485	89,249	41,357
Nonregulated and other	2,611,149	2,579,715	1,856,030
Equity earnings from investments in affiliates	71,561	217,070	182,714
Total operating revenues	9,524,372	11,333,422	9,223,466
Operating expenses:			
Electric fuel and purchased power utility	2,199,099	3,171,660	2,580,723
Cost of natural gas sold and transported utility	851,987	1,517,557	948,145
Cost of sales nonregulated and other	1,361,466	1,318,586	876,698
Other operating and maintenance expenses utility	1,501,602	1,506,039	1,446,122
Other operating and maintenance expenses nonregulated	787,968	676,408	533,379
Depreciation and amortization	1,037,429	906,303	766,746
Taxes (other than income taxes)	318,641	316,492	351,412
Writedowns and disposal losses from investments (see Notes 2 and 3)	207,290		
Special charges (see Note 2)	2,691,223	62,230	241,042
Total operating expenses	10,956,705	9,475,275	7,744,267
Operating income (loss)	(1,432,333)	1,858,147	1,479,199
Interest income	45,863	43,548	27,480
Other non-operating income	28,167	17,961	5,094
Other non-operating expense	(30,043)	(15,623)	(15,994)
Interest charges and financing costs:			
Interest charges net of amounts capitalized (includes other financing costs of $59,724, $21,058 and $20,772, respectively)	879,736	727,976	614,173
Distributions on redeemable preferred securities of subsidiary trusts	38,344	38,800	38,800
Total interest charges and financing costs	918,080	766,776	652,973
Income (loss) from continuing operations before income taxes and minority interest	(2,306,426)	1,137,257	842,806
Income taxes	(627,985)	331,371	299,030
Minority interest	(17,071)	68,199	29,994
Income (loss) from continuing operations	(1,661,370)	737,687	513,782
Income (loss) from discontinued operations net of tax (see Note 3)	(556,621)	46,992	32,006
Income (loss) before extraordinary items	(2,217,991)	784,679	545,788
		10,287	(18,960)

Extraordinary items net of income taxes of $0, $4,807 and ($8,549), respectively			
Net income (loss)	(2,217,991)	794,966	526,828
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available for common shareholders	$ (2,222,232)	$ 790,725	$ 522,587
Weighted average common shares outstanding (in thousands):			
Basic	382,051	342,952	337,832
Diluted	382,051	343,742	338,111
Earnings (loss) per share basic:			
Income (loss) from continuing operations	$ (4.36)	$ 2.14	$ 1.51
Discontinued operations (see Note 3)	(1.46)	0.14	0.09
Extraordinary items (see Note 15)		0.03	(0.06)
Earnings (loss) per share	$ (5.82)	$ 2.31	$ 1.54
Earnings (loss) per share diluted:			
Income (loss) from continuing operations	$ (4.36)	$ 2.13	$ 1.51
Discontinued operations (see Note 3)	(1.46)	0.14	0.09
Extraordinary items (see Note 15)		0.03	(0.06)
Earnings (loss) per share	$ (5.82)	$ 2.30	$ 1.54

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)

	Year ended Dec. 31,		
	2002	**2001**	**2000**
Operating activities:			
Net (loss) income	$ (2,217,991)	$ 794,966	$ 526,828
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,028,494	945,555	828,780
Nuclear fuel amortization	48,675	41,928	44,591
Deferred income taxes	(781,531)	11,190	62,716
Amortization of investment tax credits	(13,272)	(12,867)	(15,295)
Allowance for equity funds used during construction	(7,810)	(6,829)	3,848
Undistributed equity in earnings of unconsolidated affiliates	(16,478)	(124,277)	(87,019)
Gain on sale of property	(6,785)		
Write-downs and losses from investments	207,290		
Gain on sale of discontinued operations	(2,814)		
Non-cash special charges asset write-downs	3,160,374		41,991
Conservation incentive accrual adjustments	(9,152)	(49,271)	19,248
Unrealized gain on derivative financial instruments	(8,407)	(9,804)	
Extraordinary items net of tax (see Note 15)		(10,287)	18,960
Change in accounts receivable	126,073	218,353	(443,347)
Change in inventories	8,620	(178,530)	21,933
Change in other current assets	67,596	340,478	(484,288)
Change in accounts payable	80,338	(325,946)	713,069
Change in other current liabilities	156,471	142,617	183,679
Change in other noncurrent assets	(203,997)	(329,442)	(130,764)
Change in other noncurrent liabilities	99,417	136,178	102,795
Net cash provided by operating activities	1,715,111	1,584,012	1,407,725
Investing activities:			
Nonregulated capital expenditures and asset acquisitions	(1,502,601)	(4,259,791)	(2,196,168)
Utility capital/ construction expenditures	(906,341)	(1,105,989)	(984,935)
Proceeds from sale of discontinued operations	160,791		
Allowance for equity funds used during construction	7,810	6,829	(3,848)
Investments in external decommissioning fund	(57,830)	(54,996)	(48,967)
Equity investments, loans, deposits and sales of nonregulated projects	(118,844)	154,845	(93,366)
Restricted cash	(220,800)		
Collection of loans made to nonregulated projects	22,498	6,374	17,039
Other investments net	(102,457)	84,769	(36,749)
Net cash used in investing activities	(2,717,774)	(5,167,959)	(3,346,994)
Financing activities:			
Short-term borrowings net	(663,365)	708,335	42,386
Proceeds from issuance of long-term debt	2,521,375	3,777,075	3,565,227
Repayment of long-term debt, including reacquisition premiums	(362,760)	(860,623)	(1,667,335)
Proceeds from issuance of common stock	581,212	133,091	116,678

Proceeds from NRG stock offering		474,348	453,705
Dividends paid	(496,375)	(518,894)	(494,992)
Net cash provided by financing activities	1,580,087	3,713,332	2,015,669
Effect of exchange rate changes on cash	6,448	(4,566)	360
Net increase in cash and cash equivalents discontinued operations	56,096	(21,570)	(57,638)
Net increase in cash and cash equivalents continuing operations	639,968	103,249	19,122
Cash and cash equivalents at beginning of year	261,305	158,056	138,934
Cash and cash equivalents at end of year	$ 901,273	$ 261,305	$ 158,056
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ 640,628	$ 708,560	$ 610,584
Cash paid for income taxes (net of refunds received)	$ 24,935	$ 327,018	$ 216,087

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)

	Dec. 31, 2002	Dec. 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 901,273	$ 261,305
Restricted cash	305,581	142,676
Accounts receivable net of allowance for bad debts: $92,745 and $37,487, respectively	961,060	1,048,073
Accrued unbilled revenues	390,984	495,994
Materials and supplies inventories at average cost	321,863	308,593
Fuel inventory at average cost	207,200	250,043
Natural gas inventories replacement cost in excess of LIFO: $20,502 and $11,331, respectively	147,306	126,563
Recoverable purchased natural gas and electric energy costs	63,975	52,583
Derivative instruments valuation at market	62,206	20,794
Prepayments and other	267,185	307,169
Current assets held for sale	108,535	316,621
Total current assets	3,737,168	3,330,414
Property, plant and equipment, at cost:		
Electric utility plant	16,516,790	16,099,655
Nonregulated property and other	8,411,088	6,924,894
Natural gas utility plant	2,603,545	2,493,028
Construction work in progress: utility amounts of $856,008 and $669,895, respectively	1,513,807	3,663,371
Total property, plant and equipment	29,045,230	29,180,948
Less accumulated depreciation	(10,303,575)	(9,495,835)
Nuclear fuel net of accumulated amortization: $1,058,531 and $1,009,855, respectively	74,139	96,315
Net property, plant and equipment	18,815,794	19,781,428
Other assets:		
Investments in unconsolidated affiliates	1,001,380	1,196,702
Notes receivable, including amounts from affiliates of $206,308 and $202,411, respectively	987,714	779,186
Nuclear decommissioning fund and other investments	732,166	695,070
Regulatory assets	576,403	502,442
Derivative instruments valuation at market	93,225	96,095
Prepaid pension asset	466,229	378,825
Goodwill, net	35,538	36,916
Intangible assets, net	68,210	66,700
Other	364,243	360,158
Noncurrent assets held for sale	379,772	1,530,178
Total other assets	4,704,880	5,642,272

Total assets	$ 27,257,842	$28,754,114

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars) (Continued)

	Dec. 31, 2002	Dec. 31, 2001
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 7,756,261	$ 392,938
Short-term debt	1,541,963	2,224,812
Accounts payable	1,399,195	1,263,690
Taxes accrued	267,214	246,098
Dividends payable	75,814	130,845
Derivative instruments valuation at market	38,767	83,122
Other	749,521	698,142
Current liabilities held for sale	520,101	429,433
Total current liabilities	12,348,836	5,469,080
Deferred credits and other liabilities:		
Deferred income taxes	1,283,667	2,134,977
Deferred investment tax credits	169,696	184,148
Regulatory liabilities	518,427	483,942
Derivative instruments valuation at market	102,779	42,444
Benefit obligations and other	722,264	692,090
Minimum pension liability	106,897	
Noncurrent liabilities held for sale	155,962	783,297
Total deferred credits and other liabilities	3,059,692	4,320,898
Minority interest in subsidiaries	34,762	614,750
Commitments and contingencies (see Note 18)		
Capitalization (see Statements of Capitalization):		
Long-term debt	6,550,248	11,555,589
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 9)	494,000	494,000
Preferred stockholders equity	105,320	105,320
Common stockholders equity	4,664,984	6,194,477
Total liabilities and equity	$27,257,842	$28,754,114

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY AND

OTHER COMPREHENSIVE INCOME
(Thousands of Dollars)

	Common Stock Issued					Accumulated	
	Shares	Par Value	Capital in Excess Of Par Value	Retained Earnings (Deficit)	Shares Held By ESOP	Other Comprehensive Income (Loss)	Total Stockholders Equity
Balance at Dec. 31, 1999	335,277	$838,193	$2,288,254	$ 2,253,800	$(11,606)	$ (78,421)	$ 5,290,220
Net income				526,828			526,828
Currency translation adjustments						(78,508)	(78,508)
Comprehensive income for 2000							448,320
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(492,183)			(492,183)
Issuances of common stock net proceeds	5,557	13,892	102,785				116,677
Tax benefit from stock options exercised			53				53
Other				16			16
Gain recognized from NRG stock offering			215,933				215,933
Loan to ESOP to purchase shares					(20,000)		(20,000)
Repayment of ESOP loan(a)					6,989		6,989
Balance at Dec. 31, 2000	340,834	852,085	2,607,025	2,284,220	(24,617)	(156,929)	5,561,784
Net income				794,966			794,966
Currency translation adjustments						(56,693)	(56,693)
Cumulative effect of accounting change net Unrealized transition loss upon adoption of SFAS No. 133 (see Note 17)						(28,780)	(28,780)
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 17)						43,574	43,574
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						19,449	19,449
Unrealized loss marketable securities						(75)	(75)
Comprehensive income for 2001							772,441
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(516,515)			(516,515)
Issuances of common stock net proceeds	4,967	12,418	120,673				133,091
Other				(27)			(27)
Gain recognized from NRG stock offering			241,891				241,891
Repayment of ESOP loan(a)					6,053		6,053

Balance at Dec. 31, 2001	345,801	864,503	2,969,589	2,558,403	(18,564)	(179,454)	6,194,477
Net loss				(2,217,991)			(2,217,991)
Currency translation adjustments						30,008	30,008
Minimum pension liability						(107,782)	(107,782)
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 17)						(68,266)	(68,266)
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						28,791	28,791
Unrealized loss marketable securities						(457)	(457)
Comprehensive income (loss) for 2002							(2,335,697)
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(437,113)			(437,113)
Issuances of common stock net proceeds	27,148	67,870	513,342				581,212
Acquisition of NRG minority common shares	25,765	64,412	555,220			28,150	647,782
Repayment of ESOP loan(a)					18,564		18,564
Balance at Dec. 31, 2002	398,714	$996,785	$4,038,151	$ (100,942)	$	$(269,010)	$ 4,664,984

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars)

Long-Term Debt	Dec. 31, 2002	Dec. 31, 2001
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2003-2006, 3.75-4.1%	$ 9,145(a)	$ 11,225(a)
March 1, 2003, 5.875%	100,000	100,000
April 1, 2003, 6.375%	80,000	80,000
Dec. 1, 2005, 6.125%	70,000	70,000
Aug. 28, 2012, 8%	450,000	
March 1, 2011, variable rate, 6.265% at Dec. 31, 2002, and 1.8% at Dec. 31, 2001	13,700(b)	13,700(b)
March 1, 2019, 8.50% at Dec. 31, 2002, and a variable rate of 2.04% at Dec. 31, 2001	27,900(b)	27,900(b)
Sept. 1, 2019, 8.5% at Dec. 31, 2002, and a variable rate of 1.76% and 2.04% at Dec 31, 2001	100,000(b)	100,000(b)
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
April 1, 2030, 8.50% at Dec. 31, 2002, and 1.85% at Dec. 31, 2001	69,000(b)	69,000(b)
Dec. 1, 2003-2008, 4.25%-5%	14,090(a)	16,090(a)
Guaranty Agreements, Series due Feb. 1, 2003-May 1, 2003, 5.375%-7.4%	28,450(b)	29,200(b)
Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
Retail Notes due July 1, 2042, 8%	185,000	
Employee Stock Ownership Plan Bank Loans, variable rate		18,564
Other	427	390
Unamortized discount net	(8,931)	(5,015)
Total	1,788,781	1,181,054
Less redeemable bonds classified as current (see Note 6)	13,700	141,600
Less current maturities	212,762	11,134
Total NSP-Minnesota long-term debt	$ 1,562,319	$ 1,028,320
PSCo Debt new line First Mortgage Bonds, Series due:		
April 15, 2003, 6%	$ 250,000	$ 250,000
March 1, 2004, 8.125%	100,000	100,000
Nov. 1, 2005, 6.375%	134,500	134,500
June 1, 2006, 7.125%	125,000	125,000
April 1, 2008, 5.625%	18,000(b)	18,000(b)
June 1, 2012, 5.5%	50,000(b)	50,000(b)
Oct. 1, 2012, 7.875%	600,000	
April 1, 2014, 5.875%	61,500(b)	61,500(b)
Jan. 1, 2019, 5.1%	48,750(b)	48,750(b)
March 1, 2022, 8.75%	146,340	147,840
Jan. 1, 2024, 7.25%	110,000	110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars) (Continued)

Long-Term Debt continued	Dec. 31, 2002	Dec. 31, 2001
Secured Medium-Term Notes, due Nov 25, 2003-March 5, 2007, 6.45%-7.11%	175,000	190,000
Unamortized discount	(4,612)	(5,282)
Capital lease obligations, 11.2% due in installments through May 31, 2025	49,747	51,921
Total	2,064,225	1,482,229
Less current maturities	282,097	17,174
Total PSCo long-term debt	$1,782,128	$1,465,055
SPS Debt		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ 100,000	$ 100,000
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	500,000	500,000
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 1.6% at Dec. 31, 2002, and 1.7% at Dec. 31, 2001	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Unamortized discount	(1,138)	(1,425)
Total SPS long-term debt	$ 725,662	$ 725,375
NSP-Wisconsin Debt		
First Mortgage Bonds Series due:		
Oct. 1, 2003, 5.75%	$ 40,000	$ 40,000
March 1, 2023, 7.25%	110,000	110,000
Dec. 1, 2026, 7.375%	65,000	65,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6%	18,600(a)	18,600(a)
Fort McCoy System Acquisition, due Oct. 31, 2030, 7%	930	963
Senior Notes due Oct. 1, 2008, 7.64%	80,000	80,000
Unamortized discount	(1,388)	(1,475)
Total	313,142	313,088
Less current maturities	40,034	34
Total NSP-Wisconsin long-term debt	$ 273,108	$ 313,054
NRG Debt		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 257,552	$ 232,960
NRG Energy, Inc. Senior Notes, Series due Feb. 1, 2006, 7.625%	125,000	125,000
June 15, 2007, 7.5%	250,000	250,000
June 1, 2009, 7.5%	300,000	300,000
Nov. 1, 2013, 8%	240,000	240,000

Sept. 15, 2010, 8.25%	350,000	350,000
July 15, 2006, 6.75%	340,000	340,000
April 1, 2011, 7.75%	350,000	350,000
April 1, 2031, 8.625%	500,000	500,000
May 16, 2006, 6.5%	285,728	284,440
NRG Finance Co. I LLC, due May 9, 2006, various rates	1,081,000	697,500

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars) (Continued)

Long-Term Debt continued	Dec. 31, 2002	Dec. 31, 2001
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	126,500	180,000
June 15, 2015, 8.842%	130,000	130,000
Dec. 15, 2024, 9.292%	300,000	300,000
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	450,750	463,500
Sept. 15, 2024, 9.479%	300,000	300,000
MidAtlantic various, due Oct 1, 2005, 4.625%	409,201	420,892
Flinders Power Finance Pty, due September 2012, various rates 6.14-6.49% at Dec 31, 2002, and 8.56% at Dec. 31, 2001	99,175	74,886
Brazos Valley, due June 30, 2008, 6.75%	194,362	159,750
Camas Power Boiler, due June 30, 2007, and Aug. 1, 2007, 3.65% and 3.38%	17,861	20,909
Sterling Luxembourg # 3 Loan, due June 30, 2019, variable rate 7.86% at Dec. 31, 2001	360,122	329,842
Crockett Corp. LLP debt, due Dec 31, 2014, 8.13%		234,497
Csepel Aramtermelo, due Oct. 2, 2017, 3.79% and 4.846%		169,712
Hsin Yu Energy Development, due November 2006-April 2012, 4-6.475%	85,607	89,964
LSP Batesville, due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	314,300	321,875
LSP Kendall Energy, due Sept. 1, 2005, 2.65%	495,754	499,500
McClain, due Dec. 31, 2005, 6.75%	157,288	159,885
NEO, due 2005-2008, 9.35%	7,658	23,956
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	133,099	62,408
NRG Peaking Finance LLC, due 2019, 6.67%	319,362	
NRG Pike Energy LLC, due 2010, 4.92%	155,477	
PERC, due 2017-2018, 5.2%	28,695	33,220
Audrain Capital Lease Obligation, due Dec. 31, 2023, 10%	239,930	239,930
Saale Energie GmbH Schkopau Capital Lease, due May 2021, various rates	333,926	311,867
Various debt, due 2003-2007, 0.0-20.8%	92,573	147,493
Other	676	
Total	8,831,596	8,343,986
Less current maturities continuing operations	7,193,237	210,885
Less discontinued operations	445,729	851,196
Total NRG long-term debt	$1,192,630	$7,281,905

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars) (Continued)

Long-Term Debt continued	**Dec. 31, 2002**	**2001**
Other Subsidiaries Long-Term Debt		
First Mortgage Bonds Cheyenne:		
Series due April 1, 2003-Jan. 1, 2024, 7.5-7.875%	$ 12,000	$ 12,000
Industrial Development Revenue Bonds, due Sept. 1, 2021-March 1, 2027, variable rate, 1.7% and 1.8% at Dec. 31, 2002 and 2001	17,000	17,000
Viking Gas Transmission Co. Senior Notes-Series due:		
Oct. 31, 2008-Sept. 30, 2014, 6.65%-8.04%	40,421	45,181
Various Eloigne Co. Affordable Housing Project Notes, due 2003-2027, 0.3%-9.91%	41,353	47,856
Other	97,895	35,608
Total	208,669	157,645
Less current maturities	14,431	12,110
Total other subsidiaries long-term debt	$ 194,238	$ 145,535
Xcel Energy Inc. Debt		
Unsecured senior notes, due Dec. 1, 2010, 7%	$ 600,000	$ 600,000
Convertible notes, due Nov. 21, 2007, 7.5%	230,000	
Unamortized discount	(9,837)	(3,655)
Total Xcel Energy Inc. debt	$ 820,163	$ 596,345
Total long-term debt	$6,550,248	$11,555,589
Mandatorily Redeemable Preferred Securities of Subsidiary Trusts		
holding as their sole asset the junior subordinated deferrable debentures of:		
NSP-Minnesota, due 2037, 7.875%	$ 200,000	$ 200,000
PSCo, due 2038, 7.6%	194,000	194,000
SPS, due 2036, 7.85%	100,000	100,000
Total mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 494,000
Cumulative Preferred Stock authorized 7,000,000 shares of $100 par value; outstanding shares: 2002, 1,049,800; 2001, 1,049,800		
$3.60 series, 275,000 shares	$ 27,500	$ 27,500
$4.08 series, 150,000 shares	15,000	15,000
$4.10 series, 175,000 shares	17,500	17,500
$4.11 series, 200,000 shares	20,000	20,000
$4.16 series, 99,800 shares	9,980	9,980

$4.56 series, 150,000 shares	15,000	15,000
Total	104,980	104,980
Capital in excess of par value on preferred stock	340	340
Total preferred stockholders equity	$ 105,320	$ 105,320

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars) (Continued)

	Dec. 31,	
Long-Term Debt continued	**2002**	**2001**
Common Stockholders Equity		
Common stock authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2002, 398,714,039; 2001, 345,801,028	$ 996,785	$ 864,503
Capital in excess of par value on common stock	4,038,151	2,969,589
Retained earnings (deficit)	(100,942)	2,558,403
Leveraged common stock held by ESOP shares at cost: 2002, 0; 2001, 783,162		(18,564)
Accumulated other comprehensive income (loss)	(269,010)	(179,454)
Total common stockholders equity	$4,664,984	$6,194,477

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Merger and Basis of Presentation On Aug. 18, 2000, Northern States Power Co. (NSP) and New Century Energies, Inc. (NCE) merged and formed Xcel Energy Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies, except for fractional shares, and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA. References herein to Xcel Energy relates to Xcel Energy, Inc. and its consolidated subsidiaries.

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

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

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

Principles of Consolidation Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, BMG and Cheyenne. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. During the period covered by this report, Xcel Energy s regulated businesses also included Viking, which was sold in January 2003, and WGI.

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Revenue Recognition Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based of 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 estimated.

Xcel Energy s utility subsidiaries have various rate adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. In addition Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees.

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

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

NSP-Wisconsin s rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. In Wisconsin, we can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

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

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

Trading Operations In June 2002, the EITF of the FASB reached a partial consensus on Issue No. 02-03 Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10 Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF No. 02-03). The EITF concluded that all gains and losses related to energy trading activities within the scope of EITF No. 98-10, whether or not settled physically, must be shown net in the statement of operations, effective for periods ending after July 15, 2002. Xcel Energy has reclassified revenue from trading activities for all comparable prior periods reported. Such energy trading activities recorded as a component of Electric and Gas Trading Costs, which have been reclassified to offset Electric and Gas Trading Revenues to present Electric and Gas Trading Margin on a net basis, were $3.3 billion, $3.1 billion and $2.0 billion for the years ended Dec. 31, 2002, 2001 and 2000, respectively. This reclassification had no impact on operating income or reported net income.

On Oct. 25, 2002, the EITF rescinded EITF No. 98-10. With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133 must be restated to historical cost through a cumulative effect adjustment. Xcel Energy does not expect the effect of adopting this decision will be material.

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

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

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

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

Allowance for Funds Used During Construction (AFDC) and Capitalized Interest AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in Xcel Energy s rate base for establishing utility service rates. In addition to construction-related amounts, AFDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota. Interest capitalized for all Xcel Energy entities (as AFDC for utility companies) was approximately $83 million in 2002, $56 million in 2001 and $23 million in 2000.

Decommissioning Xcel Energy accounts for the future cost of decommissioning-or permanently retiring-its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. Our decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. For more information on nuclear decommissioning, see Note 19 to the Consolidated Financial Statements.

PSCo also previously operated a nuclear generating plant, which has been decommissioned and re-powered 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition, nuclear fuel expense includes fees assessed by the U.S. Department of Energy (DOE) for NSP-Minnesota s portion of the cost of decommissioning the DOE s fuel enrichment facility.

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

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

Income Taxes Xcel Energy and its domestic subsidiaries, other than NRG and its domestic subsidiaries, file consolidated federal income tax returns. NRG and its domestic subsidiaries were included in Xcel Energy s consolidated federal income tax returns prior to NRG s March 2001 public equity offering, but filed consolidated federal income tax returns, with NRG as the common parent, separate and apart from Xcel Energy for the periods of March 13, 2001, through Dec. 31, 2001, and Jan. 1, 2002, through June 3, 2002. Since becoming wholly owned indirect subsidiaries of Xcel Energy on June 3, 2002, NRG and its domestic subsidiaries have not been reconsolidated with Xcel Energy for federal income tax purposes, and each of NRG and its domestic subsidiaries will file separate federal income tax returns as a result of their inclusion in the Xcel Energy consolidated federal income tax return within the last five years. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries will be included in some, but not all, of these combined returns in 2002. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. In accordance with PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which we summarize in Note 20 to the Consolidated Financial Statements. We discuss our income tax policy for international operations in Note 11 to the Consolidated Financial Statements.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of Other Nonoperating Income. Currency exchange transactions resulted in a pretax gain (loss) of $30 million in 2002, $(57) million in 2001 and $(79) million in 2000.

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

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

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

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

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

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

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

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

Regulatory Accounting Our regulated utility subsidiaries account for certain income and expense items using SFAS No. 71 Accounting for the Effects of Certain Types of Regulation. Under SFAS No. 71:

- we defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and

- we defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 20 to the Consolidated Financial Statements.

Stock-Based Employee Compensation We have several stock-based compensation plans. We account for those plans using the intrinsic value method. We do not record compensation expense for stock options because there is no difference between the market price and the purchase price at grant date. We do, however, record compensation expense for restricted stock awarded to certain employees, which is held until the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

restriction lapses or the stock is forfeited. For more information on stock compensation impacts, see Note 12 to the Consolidated Financial Statements.

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

As of Dec. 31, 2002, the assets of these entities were approximately $155 million and long-term liabilities were approximately $87 million. Currently, investments of $62 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2002, Consolidated Balance Sheet. FIN No. 46

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

requires that for entities to be consolidated, the entities assets be initially recorded at their carrying amounts at the date the new requirement first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to the Xcel Energy s balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative effect adjustment of an accounting change. Had Xcel Energy adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. Xcel Energy plans to adopt FIN No. 46 when required in the third quarter of 2003.

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

2. Special Charges and Asset Impairments

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

considered cash flow analyses, bids and offers related to those projects. The resulting impairments were recognized as Special Charges in 2002, as follows:

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

2001 Postemployment Benefits PSCo adopted accrual accounting for postemployment benefits under SFAS No. 112 Employers Accounting for Postemployment Benefits in 1994. The costs of these benefits 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 postemployment 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 postemployment benefit costs as of June 30, 2001.

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accrued Special Charges The following table summarizes activity related to accrued special charges in 2002 and 2001 (Millions of dollars):

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

* Reported on the balance sheet in Other Current Liabilities.

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

3. Discontinued Operations and Losses on Equity Investments

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

Discontinued Operations

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Projects included in discontinued operations are as follows (Dollars in Millions):

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

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

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

Special charges from discontinued operations included in Operating & Other Expenses above include the following:

	2002	2001	2000
	(In Thousands)		
Asset Impairments Killingholme (UK)	$477,868	$	$
Hsin Yu (Taiwan)	121,864		
	599,732		
Severance and other charges:	7,389		
Total Special Charges	$607,121	$	$

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Losses Related to NRG Equity Investments

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

investments. During 2002, NRG recorded write-downs and losses on disposal of $196.2 million of equity investments as follows:

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

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

Other Equity Investment Losses

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

4. NRG Acquisition and Restructuring Plan

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

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

The process to allocate the purchase price to underlying interests in NRG assets, and to determine fair values for the interests in assets acquired resulted in approximately $62 million of amounts being allocated to fixed assets related to projects where the fair values were in excess of carrying values, to prepaid pension assets

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and to other assets. The preliminary purchase price allocation is subject to change as the final purchase price allocation and asset valuation process is completed.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Definitive documentation, in form and substance satisfactory to the parties;

(2) Between 50 percent and 100 percent of the claims represented by various NRG facilities or creditor groups (the NRG Credit Facilities) having executed an agreement, in form and substance satisfactory to Xcel Energy, to support the settlement;

(3) Various stages of the implementation of the settlement occurring by dates currently being negotiated, with the consummation of the settlement to occur by Sept. 30, 2003;

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(4) The receipt of releases in favor of Xcel Energy by at least 85 percent of the claims represented by the NRG Credit Facilities;

(5) The receipt by Xcel Energy of all necessary regulatory approvals; and

(6) No downgrade prior to consummation of the settlement of any Xcel Energy credit rating from the level of such rating as of March 25, 2003.

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

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

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved.

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

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

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

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

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

Xcel Energy believes that the ultimate resolutions of NRG s financial difficulties and going-concern uncertainty will not affect Xcel Energy s ability to continue as a going concern. Xcel Energy is not dependent on cash flows from NRG, nor is Xcel Energy contingently liable to creditors of NRG in an amount material to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Xcel Energy s liquidity. Xcel Energy believes that its cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund its non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, Xcel Energy believes it will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

5. Short-Term Borrowings

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

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

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

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

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

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

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

6. Long-Term Debt

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

7. NRG Debt and Capital Leases

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term and Short-term Debt Defaults

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

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

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

Short-term Debt

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Long-term Debt Corporate Debt

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

£160 million of 7.97 percent debt. The 30-day grace period to make payment related to this issue has passed and NRG did not make the required payments. NRG is in default on these bonds.

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

Long-term Debt Subsidiary

NEO Corp. The various NEO notes are term loans. The loans are secured principally by long-term assets of NEO Landfill Gas collection system. NEO Landfill Gas is required to maintain compliance with certain covenants primarily related to incurring debt, disposing of the NEO Landfill Gas assets, and affiliate transactions. On Oct. 30, 2002, NRG failed to make $3.1 million in payments under certain non-operating interest acquisition agreements. As a result, NEO Corp., a direct wholly owned subsidiary of NRG, and NEO Landfill Gas, Inc., an indirect wholly owned subsidiary of NRG, failed to make approximately $1.4 million in loan payments. Also, the subsidiaries of NEO Corp. and NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various agreements. NRG received an extension until November 2002 with respect to NEO Landfill Gas, Inc. to make payments under such agreements, and such payments were made during the extension period. The payments relating to NEO Corp. were not made, and the loan was due and payable on Dec. 20, 2002. A letter of credit was drawn to pay the NEO Corp. loan in full on Dec. 23, 2002. As of Dec. 31, 2002, NEO Landfill Gas, Inc. was in default under the loan agreement dated July 6, 1998 due to the failure to meet the insurance requirements under the loan document. On Jan. 30, 2003, NRG failed to make $2.7 million in payments under certain acquisition agreements. As a result, NEO Landfill Gas, Inc. failed to make its payment due on Jan. 30, 2003, under the loan agreement and the subsidiaries of NEO Landfill Gas failed to make their payments pursuant to various agreements.

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

NRG South Central Generating LLC In March 2000, NRG South Central Generating LLC, an indirect wholly owned subsidiary of NRG, issued $800 million of senior secured bonds in a two-part offering to finance its acquisition of the Cajun generating facilities. The bonds are secured by a security interest in NRG Central U.S. LLC s and South Central Generating Holding LLC s membership interests in NRG South Central and NRG South Central s membership interests in Louisiana Generating and all of the assets related to the Cajun facilities, including its rights under a guarantor loan agreement and all inter-company notes between it and Louisiana Generating, and a revenue account and a debt service reserve account. On Sept. 15,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2002, NRG South Central Generating missed a $47-million principal and interest payment. The 15-day grace period to make payment related to this issue has passed,and NRG South Central Generating did not make the required payments. In January 2003, the South Central Generating bondholders unilaterally withdrew $35.6 million from the restricted revenue account, relating to the Sept. 15, 2002, interest payment and fees. On March 17, 2003, South Central bondholders were paid $34.4 million due in relation to the semi-annual interest payment, and the $12.8 million principal payment was deferred. NRG South Central remains in default on these notes.

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term Debt Credit Facilities

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

Facility	Available line of credit	Recourse to NRG	End date	Outstanding Dec. 31, 2002	Rate at Dec. 31, 2002
			(Currency in thousands)		
Revolving lines of credit:					
NRG Finance Co. I LLC	$2,000,000	Yes	May 2006	$1,081,000	4.92%
Term loanfacilities:					
MidAtlantic	$ 580,000	No	November 2005	$ 409,200	3.30%
LSP Kendall Energy	$ 554,200	No	September 2005	$ 495,800	3.19%
Brazos Valley	$ 180,000	No	June 2008	$ 194,400	4.41%
McClain	$ 296,000	No	November 2006	$ 157,300	4.57%

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Preferred Stock

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

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

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

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

9. Mandatorily Redeemable Preferred Securities of Subsidiary Trusts

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Joint Plant Ownership

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

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

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota s share of operating expenses for Sherco 3 is included in the applicable utility components of operating expenses. PSCo s assets include approximately 320 megawatts of jointly owned generating capacity. PSCo s share of operating expenses and construction expenditures are included in the applicable utility components of operating expenses. NRG s share of operating expenses and construction expenditures are included in the applicable nonregulated components of operating expenses. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

11. Income Taxes

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Income taxes comprise the following expense (benefit) items:

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of NRG s foreign operations. However, no U.S. income tax benefit has been provided on the cumulative amount of unremitted losses of $339.7 million at Dec. 31, 2002 due to the uncertainty of realization.

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

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

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

12. Common Stock and Incentive Stock Plans

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

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

Other common stock equivalents included stock options, as discussed further, and NRG equity units. See discussion of NRG equity units, which are convertible to Xcel Energy common stock, at Note 7. Due to the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

losses experienced in 2002, these equivalents were also antidilutive and were not incorporated in the common stock and equivalents calculation in 2002.

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

	2002	2001	2000
	(In Thousands, except per share amounts)		
Basic EPS Calculation:			
Earnings (loss) available for common	$(2,222,232)	$790,725	$522,587
Weighted average common stock outstanding	382,051	342,952	337,832
Basic earnings per share	$ (5.82)	$ 2.31	$ 1.54
Diluted Calculation:			
Earnings (loss) available for common	$(2,222,232)	$790,725	$522,587
Adjustments for Dilutive Securities			
Earnings (loss) for Dilutive Securities	$(2,222,232)	$790,725	$522,587
Weighted average common stock outstanding	382,051	342,952	337,832
Adjustments for Common Stock Equivalents		790	279
Weighted average Common Stock and Equivalents	382,051	343,742	338,111
Diluted earnings per share	$ (5.82)	$ 2.30	$ 1.54

Incentive Stock Plans Xcel Energy and some of its subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate our earnings per share include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables below include awards made by us and some of our predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally from two to three years from the date of grant. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment. Restricted shares have a value equal to the market trading price of Xcel Energy s stock at the grant date. We granted 50,083 restricted shares in 2002 when the grant-date market price was $22.83, 21,774 restricted shares in 2001 when the grant-date market price was $26.06 and 58,690 restricted shares in 2000 when the grant-date market price was $19.25. Compensation expense related to these awards was immaterial.

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

We apply Accounting Principles Board Opinion No. 25 in accounting for our stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options as the exercise price of the options equals the fair-market value of our common stock at the date of grant. If we had used the SFAS No. 123 method of accounting, earnings would have been the same for 2002 and reduced by approximately 1 cent per share for 2001 and 2 cents per share for 2000.

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

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

* There were no options granted in 2002.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dividend and Other Capital-Related Restrictions Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of Xcel Energy were a deficit of $101 million at Dec. 31, 2002 and, accordingly, dividends cannot be declared until earnings in 2003 are sufficient to eliminate this deficit or Xcel Energy is granted relief under the PUHCA. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until Sept. 30, 2003. Xcel Energy did not declare a dividend on its Common Stock during the first quarter of 2003. It is not known when or if the SEC will act on this request.

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

In addition, NSP-Minnesota s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $825 million in additional cash dividends on common stock at Dec. 31, 2002.

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

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

13. Benefit Plans and Other Postretirement Benefits

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Xcel Energy s policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. The target range for our pension asset allocation is 75 to 80 percent with equity investments, 5 to 10 percent with fixed income investments, no cash investments and 10 to 15 percent with nontraditional investments (such as real estate and timber ventures). At Dec. 31, 2002, the actual pension portfolio mix was 68 percent equity, 16 percent fixed income, 4 percent cash investments and 12 percent nontraditional investments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Defined Contribution Plans Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $23 million in 2002, $29 million in 2001 and $24 million in 2000.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Postretirement Health Care Benefits Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. However, employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

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

Regulatory agencies for nearly all of Xcel Energy s retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. PSCo transitioned to full accrual accounting for SFAS No. 106 costs between 1993 and 1997, consistent with the accounting requirements for rate-regulated enterprises. The Colorado jurisdictional SFAS No. 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS No. 106 costs, with regulatory differences fully amortized prior to 1997.

Certain state agencies that regulate Xcel Energy s utility subsidiaries have also issued guidelines related to the funding of SFAS No. 106 costs. SPS is required to fund SFAS No. 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo is required to fund SFAS No. 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Minnesota and Wisconsin retail regulators required external funding of accrued SFAS No. 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed-income securities and cash equivalents.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of net periodic postretirement benefit cost are:

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

14. Equity Investments

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

A summary of Xcel Energy s significant equity method investments is listed in the following table:

Name	Entity Form	Xcel Energy Owner Functions	Geographic Area	Dec. 31, 2002 Economic Interest
Loy Yang Power A	Partnership	None	Australia	25.37%
Gladstone Power Station	Joint Venture	Operator	Australia	37.50%
MIBRAG GmbH	Partnership	None	Europe	50.00%
West Coast Power	Partnership	Operator	USA	50.00%
Lanco Kondapalli Power(1)	Partnership	Operator	India	30.00%
Rocky Road Power	Partnership	Operator	USA	50.00%
Schkopau	Tenants in Common	None	Europe	41.67%
ECK Generating(1)	Partnership	Operator	Czech Republic USA	44.50%
Commonwealth Atlantic Mustang	Joint Venture	None	USA	25.00%
Quixx Linden L.P.	General/ Limited Partnership	Operator	USA	50.00%
Borger Energy L.P.	General/ Limited Partnership	Operator	USA	45.00%
Various Affordable Housing Limited Partnerships	Limited Partnerships	Various	USA	20.00% - 99.99%

(1) Pending disposition at Dec. 31, 2002.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Results of Operations

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

Financial Position

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

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

Results of Operations

	2001
	(Millions of Dollars)
Operating revenues	$1,562
Operating income (loss)	345

Net income (loss)	326

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Position

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

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

15. Extraordinary Items

SPS In the second quarter of 2000, SPS discontinued regulatory accounting under SFAS No. 71 for the generation portion of its business due to the issuance of a written order by the Public Utility Commission of Texas (PUCT) in May 2000, addressing the implementation of electric utility restructuring. SPS transmission and distribution business continued to meet the requirements of SFAS No. 71, as that business was expected to remain regulated. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs totaling approximately $19.3 million. This resulted in an after-tax extraordinary charge of approximately $13.7 million. During the third quarter of 2000, SPS recorded an extraordinary charge of $8.2 million before tax, or $5.3 million after tax, related to the tender offer and defeasance of first mortgage bonds. The first mortgage bonds were defeased to facilitate the legal separation of generation, transmission and distribution assets, which was expected to eventually occur in 2001 under restructuring requirements in effect in 2000.

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

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

As a result of these recent legislative developments, SPS reapplied the provisions of SFAS No. 71 for its generation business during the second quarter of 2001. More than 95 percent of SPS retail electric revenues are from operations in Texas and New Mexico. Because of the delays to electric restructuring passed by Texas

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and New Mexico, SPS previous plans to implement restructuring, including the divestiture of generation assets, have been abandoned. Accordingly, SPS will now continue to be subject to rate regulation under traditional cost-of-service regulation, consistent with its past accounting and ratemaking practices for the foreseeable future, at least until 2007.

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

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

16. Financial Instruments

Fair Values

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

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

The carrying amount of cash, cash equivalents and short-term investments approximates fair value because of the short maturity of those instruments. The fair values of Xcel Energy s long-term investments, mainly debt securities in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The balance in notes receivable consists primarily of fixed rate, from 4.75 to 19.5 percent, and variable rate notes that mature between 2003 and 2024. Notes receivable include a $366-million direct financing lease related to a long-term sales agreement for NRG Energy s Schkopau project, and other notes related to projects at NRG Energy that are generally secured by equity interests in partnerships and joint ventures. The fair value of Xcel Energy s long-term debt and the mandatorily redeemable preferred securities are estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2002 and 2001. These fair value estimates have not been comprehensively revalued for purposes of these

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Consolidated Financial Statements since that date, and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

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

Nature of Guarantee	Guarantor	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
		($ Millions)	($ Millions)			($ Millions)
Guarantee performance and payment of surety bonds for itself and its subsidiaries	Xcel Energy(d)	$342.7	$ 5.6	2003, 2004, 2005, 2007 and 2012	(b)	$10.0
Guarantee performance and payment of surety bonds for those subsidiaries	Various subsidiaries(e)	$493.8	$116.0	2003, 2004 and 2005	(b)	N/A
Guarantees made to facilitate e prime s natural gas acquisition, marketing and trading operations	Xcel Energy	$264.0	$ 88.0	Continuous	(a)	N/A
Guarantees for NRG liabilities associated with power marketing obligations, fuel purchasing transactions and hedging activities	Xcel Energy	$219.5	$ 96.3	Latest expiration is Dec. 31, 2003	(a)	N/A
Guarantee of payments of notes issued by Guardian Pipeline, LLC, of which Viking is one of three partners	Xcel Energy	$ 60	$ 60	Terminated Jan. 17, 2003	(a)	N/A
Two guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements	Xcel Energy	$ 26.5	$ 1.7	2011 and 2013	(a)	N/A
Construction contract performance guarantee of Utility Engineering subsidiaries	Xcel Energy	$ 25.0	$ 25.0	July 1, 2003	(c)	N/A

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Nature of Guarantee	Guarantor	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
		($ Millions)	($ Millions)			($ Millions)
Guarantee for obligations of a customer in connection with an electric sale agreement	SPS(f)	$ 17.7	$ 11.0	September 2003	(a)	Electric transmission system
Guarantees related to energy conservation projects in which Planergy has guaranteed certain energy savings to the customer	Xcel Energy	$ 26.7	$ 26.7	Expired Jan. 1, 2003	N/A	N/A
Guarantee for payments related to energy or financial transactions for XERS Inc., a nonregulated subsidiary of Xcel Energy	Xcel Energy	$ 11.1	$ 4.1	Continuous	(a)	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$ 6.2	$ 6.2	Latest expiration in 2007	(a)	Security interest in underlying receivable agreements
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$ 16.4	$ 5.4	Continuous	(a)	N/A

(a) Nonperformance and/or nonpayment

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

(c) Failure to meet emission compliance at relevant facility.

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

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

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

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

NRG is directly liable for the obligations of certain of its project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. In addition, in connection with the purchase and sale of fuel emission credits and power generation products to and from third parties with respect to the operation of some of NRG s generation facilities in the United States, NRG

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

may be required to guarantee a portion of the obligations of certain of its subsidiaries. As of Dec. 31, 2002, NRG s obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $374.0 million.

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

Fair Value of Derivative Instruments

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

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

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

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

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

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

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

Foreign Currency Xcel Energy and its subsidiaries have two foreign currency swaps to hedge or protect foreign currency denominated cash flows. At Dec. 31, 2002 and 2001, the net notional amount of these contracts was approximately $3.0 million and $46.3 million, respectively. The fair value of these contracts as of Dec. 31, 2002 and 2001, was a liability of approximately $0.3 million and $2.4 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one or two years, to provide financial guarantees for certain operating obligations. In addition, NRG uses letters of credit for nonregulated equity commitments, collateral for credit agreements, fuel purchase and operating commitments, and bids on development projects. At Dec. 31, 2002, there were $154.6 million in letters of credit outstanding, including $110.0 million related to NRG commitments. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

17. Derivative Valuation and Financial Impacts

Use of Derivatives to Manage Risk

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy s risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

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

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

Derivatives as Hedges

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Impacts of Derivatives

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

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

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

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

18. Commitments and Contingencies

Commitments

Legislative Resource Commitments In 1994, NSP-Minnesota received Minnesota legislative approval for additional on-site temporary spent fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Seventeen dry cask containers were approved. As of Dec. 31, 2002, NSP-Minnesota had loaded 17 of the containers. The Minnesota Legislature established several energy resource and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. These commitments can be met by building, purchasing or, in the case of biomass, converting generation resources.

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

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

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

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

Support and Capital Subscription Agreement In May 2002, Xcel Energy and NRG entered into a support and capital subscription agreement pursuant to which Xcel Energy agreed under certain circum-

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stances to provide up to $300 million to NRG. Xcel Energy has not to date provided funds to NRG under this agreement. However, Xcel Energy is willing to make a contribution of $300 million if the restructuring plan discussed earlier is approved by the creditors. See additional discussion of NRG restructuring at Note 4.

Leases Our subsidiaries lease a variety of equipment and facilities used in the normal course of business. Some of these leases qualify as capital leases and are accounted for accordingly. The capital leases expire between 2002 and 2025. The net book value of property under capital leases was approximately $624 million and $605 million at Dec. 31, 2002 and 2001, respectively. Assets acquired under capital leases are recorded as property at the lower of fair-market value or the present value of future lease payments and are amortized over their actual contract term in accordance with practices allowed by regulators. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

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

Future commitments under operating and capital leases are:

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

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

Fuel Contracts Xcel Energy has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2003 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.3 billion of coal, $122.2 million of nuclear fuel and $1.6 billion of natural gas including $1.2 billion of natural gas storage and transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy s risk of loss, in the form of increased costs, from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of most fuel costs.

Purchased Power Agreements The utility and nonregulated subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo, SPS and certain nonregulated subsidiaries have various pay-for-performance contracts with expiration dates through the year 2050. In general, these contracts

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

NSP-Minnesota has a 500-megawatt participation power purchase commitment with Manitoba Hydro, which expires in 2005. The cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota s Sherco 3 generating plant, adjusted to 1993 dollars. This agreement was extended through a new agreement during 2002 to include the period starting May 2005 through April 2015. The cost of the agreement for this extended period is based on a base price, which was established from May 2001 through April 2002 and will be escalated by the change in the United States Gross National Product to reflect the current year. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro s system capacity and account for approximately 9 percent of NSP-Minnesota s 2002 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2002, the estimated future payments for capacity that the utility and nonregulated subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

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

Environmental Contingencies

We are subject to regulations covering air and water quality, land use, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating our facilities. This includes NRG, which is subject to regional, federal and international environmental regulation.

Site Remediation We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2002, there were three categories of sites:

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

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

To estimate the cost to remediate these sites, we may have to make assumptions when facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution-control technologies, the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

period over which remediation will be performed and paid for, changes in environmental remediation and pollution-control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

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

insurance coverage;

other parties that have contributed to the contamination; and

customers.

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

Approximately $15 million of the long-term liability and $4 million of the current liability relate to a U.S. Department of Energy assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. These environmental liabilities do not include accruals recorded and collected from customers in rates for future nuclear fuel disposal costs or decommissioning costs related to NSP-Minnesota s nuclear generating plants. See Note 19 to the Consolidated Financial Statements for further discussion of nuclear obligations.

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

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

In the interim, NSP-Wisconsin has recorded a liability of $19 million for its estimate of its share of the cost of remediating the portion of the Ashland site that it owns, using information available to date and reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities.

As an interim action, Xcel Energy proposed, and the EPA and WDNR have approved, a coal tar removal/ groundwater treatment system for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

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

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

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

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

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

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Leyden Gas Storage Facility In February 2001, the CPUC granted PSCo s application to abandon the Leyden natural gas storage facility (Leyden) after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. Since late 2001, PSCo has operated the facility to withdraw the recoverable gas in inventory. Beginning in 2003, PSCo will start to flood the facility with water, as part of an overall plan to convert Leyden into a

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

municipal water storage facility owned and operated by the city of Arvada, Colo. As of Dec. 31, 2002, PSCo has deferred approximately $4.5 million of costs associated with engineering buffer studies, damage claims paid to landowners and other closure costs. PSCo expects to incur an additional $6 million to $8 million of costs through 2005 to complete the decommissioning and closure of the facility. PSCo believes that these costs will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

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

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

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

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

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

Nuclear Insurance NSP-Minnesota s public liability for claims resulting from any nuclear incident is limited to $9.4 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $9.2 billion of exposure is funded by the Secondary Financial Protection Program,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $88 million for each of its three licensed reactors to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $1.5 billion for each of NSP-Minnesota s two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $7.5 million for business interruption insurance and $21.6 million for property damage insurance if losses exceed accumulated reserve funds.

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

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

Legal Contingencies

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

St. Cloud Gas Explosion On Dec. 11, 1998, a natural gas explosion in St. Cloud, Minn., killed four people, including two NSP-Minnesota employees, injured approximately 14 people and damaged several buildings. The accident occurred as a crew from Cable Constructors Inc. (CCI) was installing fiber-optic cable for Seren. Seren, CCI and Sirti, an architecture/ engineering firm retained by Seren, are named as defendants in 24 lawsuits relating to the explosion. NSP-Minnesota, Seren s parent company at the time, is a defendant in 21 of the lawsuits. In addition to compensatory damages, plaintiffs are seeking punitive damages against CCI and Seren. NSP-Minnesota and Seren deny any liability for this accident. On July 11, 2000, the National Transportation Safety Board issued a report, which determined that CCI s inadequate installation procedures and delay in reporting the natural gas hit were the proximate causes of the accident. NSP-Minnesota has a self-insured retention deductible of $2 million with general liability coverage limits of $185 million. Seren s primary insurance coverage is $1 million and its secondary insurance coverage is $185 million. The ultimate cost to Xcel Energy, NSP-Minnesota and Seren, if any, is presently unknown.

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

Although the complaints contain a number of allegations, the basic claim is that, by underbidding forward contracts and exporting electricity to surrounding markets, the defendants, acting in collusion, were able to drive up wholesale prices on the Real Time and Replacement Reserve markets, through the Western Coordinating Council and otherwise. The complaints allege that the conduct violated California antitrust and unfair competition laws. NRG does not believe that it has engaged in any illegal activities, and intends to vigorously defend these lawsuits. These six civil actions brought against NRG and other power generators and power traders in California have been consolidated in the San Diego County Superior Court, and the plaintiffs in these six consolidated civil actions filed a master amended complaint reiterating the allegations contained in their complaints and alleging that the defendants anti-competitive conduct damaged the general public and class members in an amount in excess of $1.0 billion. Two of the defendants in these actions, Reliant and Duke, subsequently filed cross-complaints naming additional market participants, some of whom removed the actions to the United States District Court for the Southern District of California federal court. Now under advisement in that court is the plaintiffs motion to remand the cases to state court and motions by the cross-defendants to dismiss the cases against them.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

See Note 4 for additional discussion of possible NRG bankruptcy.

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

Xcel Energy, Inc. Securities Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy s common stock between Jan. 31, 2001 and July 26, 2002, was filed in the United States District Court for the District of Minnesota. The complaint named Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Edward J. McIntyre, former vice president and chief

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial officer; and former chairman, James J. Howard as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act and Rule 10(b-5) related to allegedly false and misleading disclosures concerning various issues including but not limited to round trip energy trades, the nature, extent and seriousness of liquidity and credit difficulties at NRG, and the existence of cross-default provisions (with NRG credit agreements) in certain of Xcel Energy s credit agreements. After the filing of the lawsuit, several additional lawsuits were filed with similar allegations, one of which added claims on behalf of a purported class of purchasers of two series of Senior Notes issued by NRG in January 2001. The cases have all been consolidated, and a consolidated amended complaint has been filed. The amended complaint charges false and misleading disclosures concerning round trip energy trades and the existence of provisions in Xcel Energy s credit agreements for cross-defaults in the event of a default by NRG in one or more of NRG s credit agreements; it adds as additional defendants Gary R. Johnson, General Counsel, Richard C. Kelly, president of Xcel Energy Enterprises, three former executive officers of NRG, David H. Peterson, Leonard A. Bluhm, and William T. Pieper, and a former independent director of NRG, Luella G. Goldberg; and it adds claims of false and misleading disclosures, also regarding round trip trades and the cross-default provisions, as well the extent to which the fortunes of NRG were tied to Xcel Energy, especially in the event of a buyback of NRG s publicly owned shares, under Section 11 of the Securities Act with respect to issuance of the Senior Notes. The amended complaint seeks compensatory and rescissionary damages, interest, and an award of fees and expenses. The defendants have not yet responded to the amended complaint. Discovery has not commenced.

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

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

Stone & Webster, Inc. v. Xcel Energy, Inc. On Oct. 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court in Mississippi against Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Richard C. Kelly, president of Xcel Energy Enterprises; NRG and certain NRG subsidiaries. Plaintiffs allege they had a contract with a single

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

purpose NRG subsidiary for construction of a power generation facility, which was abandoned before completion but after substantial sums had been spent by plaintiffs. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy, and aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The complaint seeks compensatory damages of at least $130 million plus demobilization and cancellation costs and punitive damages at least treble the compensatory damages. On Dec. 23, 2002, defendants filed motions to dismiss the complaint, which have not yet been ruled upon. No trial date has been set in this matter, and Xcel Energy cannot presently predict the outcome of this dispute. Plaintiffs have commenced what they characterize as jurisdictional discovery, which defendants are resisting.

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

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

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

On Oct. 2, 2000, plaintiff NiMo commenced an action against NRG to recover net damages through the date of judgment, as well as any additional amounts due and owing for electric service provided to the Dunkirk Plant after Sept. 18, 2000. NiMo claims that NRG has failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999 and continuing to Sept. 18, 2000 and thereafter. On Aug. 9, 2002 the parties filed a stipulation consolidating this action with two other actions against the Huntley and Oswego subsidiaries of NRG. On Oct. 8, 2002, a Stipulation and Order was filed in the Erie County Clerk s Office

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

staying this action pending submission of some or all of the disputes in the action to the FERC. NRG cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

Other Contingencies

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

which communicated a position adverse to PSRI. Consequently, we expect the IRS examination division to begin the process of disallowing the interest expense deductions for the tax years 1993 through 1997.

After consultation with tax counsel, it is Xcel Energy s position that the IRS determination is not supported by the tax law. Based upon this assessment, management continues to believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the tax law. Therefore, Xcel Energy intends to challenge the IRS determination, which could require several years to reach final resolution. Although the ultimate resolution of this matter is uncertain, management continues to believe the resolution of this matter will not have a material adverse impact on Xcel Energy s financial position, results of operations or cash flows. For this reason, PSRI has not recorded any provision for income tax or interest expense related to this matter and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. However, defense of Xcel Energy s position may require significant cash outlays on a temporary basis, if refund litigation is pursued in United States District Court.

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

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

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

19. Nuclear Obligations

Fuel Disposal NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota s nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE s permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately $13 million in 2002, $11 million in 2001 and $12 million in 2000. In total, NSP-Minnesota had paid approximately $312 million to the DOE through Dec. 31, 2002. However, we cannot determine whether the amount and method of the DOE s assessments to all utilities will be sufficient to fully fund the DOE s permanent storage or disposal facility.

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

NSP-Minnesota has its own temporary, on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants. With the dry cask storage facilities approved in 1994, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least 2007. The

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Monticello nuclear plant has storage capacity to continue operations until 2010. Storage availability to permit operation beyond these dates is not assured at this time. We are investigating all of the alternatives for spent fuel storage until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities. If on-site temporary storage at Prairie Island reaches approved capacity, we could seek interim storage at this or another contracted private facility, if available.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE s uranium enrichment facilities. In 1993, NSP-Minnesota recorded the DOE s initial assessment of $46 million, which is payable in annual installments from 1993 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2002 was $4 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, we deferred the unamortized assessment of $21 million at Dec. 31, 2002, as a regulatory asset.

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

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

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

Consistent with cost recovery in utility customer rates, we record annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Funding presumes that current costs will escalate in the future at a rate of 4.35 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding. Unrealized gains on nuclear decommissioning investments are deferred as Regulatory Liabilities based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

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The MPUC last approved NSP-Minnesota s nuclear decommissioning study request in April 2000, using 1999 cost data. A new filing was submitted to the MPUC in October 2002 and requests continuation of the current accrual. Since the timeframe is getting short on the recovery of the Prairie Island costs, less than five years at the start of 2003, NSP-Minnesota has recommended that the next filing be submitted in October 2003. The Department of Commerce has recommended that the internal fund, which is currently being transferred to the external funds, be transferred over a shorter period of time. This proposal would increase the fund cash contribution by approximately $13 million in 2003, but may not have a statement of operations impact. Although we expect to operate Prairie Island through the end of each unit s licensed life, the approved capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2007. This is about seven years earlier than each unit s licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding spent-fuel storage. We believe future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2002, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in one to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

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

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

Decommissioning expenses recognized include the following components:

	2002	2001	2000
	(Thousands of dollars)		
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$ 51,433	$ 51,433	$ 51,433
Internally funded (including interest costs)	(18,797)	(17,396)	(16,111)
	(32)	4,535	5,151

Interest cost on externally funded decommissioning obligation			
Earnings from external trust funds	32	(4,535)	(5,151)
Net decommissioning accruals recorded	$ 32,636	$ 34,037	$ 35,322

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

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

20. Regulatory Assets and Liabilities

Our regulated businesses prepare their Consolidated Financial Statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Consolidated Financial Statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow us to collect, or may require us to pay back to customers in future electric and natural gas rates. Any portion of our business that is not regulated cannot use SFAS No. 71 accounting. The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

	Note Reference	Remaining Amortization Period	2002	2001
			(Thousands of dollars)	
AFDC recorded in plant(a)		Plant Lives	$154,158	$149,591
Conservation programs(a)(e)		Up to Five Years	53,860	65,825
Losses on reacquired debt	1	Term of Related Debt	85,888	95,394
Environmental costs	18,19	To be determined	30,974	20,169
Unrecovered electric production costs(d)	1	27 months	67,709	
Unrecovered natural gas costs(b)	1	One to Two Years	11,950	11,316
Deferred income tax adjustments	1	Mainly Plant Lives	18,611	17,799
Nuclear decommissioning costs(c)		Up to Eight Years	53,567	68,484
Employees postretirement benefits other than pension	13	Ten Years	38,899	42,942
Employees postemployment benefits	2	One Year		119
Renewable resource costs		To be determined	26,000	17,500
State commission accounting adjustments(a)		Plant Lives	19,157	7,578
Other		Various	15,630	5,725
Total regulatory assets			$576,403	$502,442
Investment tax credit deferrals			$109,571	$117,257
Unrealized gains from decommissioning investments	19		112,145	149,041

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	Note Reference	Remaining Amortization Period	2002	2001
			(Thousands of dollars)	
Pension costs-regulatory differences	13		287,615	215,687
Interest on income tax refunds			6,569	
Fuel costs, refunds and other			2,527	1,957
Total regulatory liabilities			$518,427	$483,942

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

(b) Excludes current portion with expected rate recovery within 12 months of $12 million and $22 million for 2002 and 2001, respectively.

(c) These costs do not relate to NSP-Minnesota s nuclear plants. They relate to DOE assessments, as discussed previously, and unamortized costs for PSCo s Fort St. Vrain nuclear plant decommissioning.

(d) Excludes current portion with expected rate recovery within 12 months of $54 million and $0 million for 2002 and 2001, respectively

(e) 2001 amount includes accrued conservation incentives, which were approved in 2001.

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The adoption of SFAS No. 143 in 2003 will also affect Xcel Energy s accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a Generally Accepted Accounting Principles liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, the estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 143 that are accrued in accumulated depreciation, are as follows at December 31, 2002:

	(Millions of Dollars)
NSP-Minnesota	$304
NSP-Wisconsin	70
PSCo.	329
SPS	97

21. Segments and Related Information

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

Xcel Energy s Electric Utility generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, New Mexico, Wyoming, Kansas and Oklahoma. It also makes sales for resale and provides wholesale transmission service to various entities in the United States. Electric Utility also includes electric trading.

Xcel Energy s Natural Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan, Arizona, Colorado and Wyoming.

NRG develops, acquires, owns and operates several nonregulated energy-related businesses, including independent power production, commercial and industrial heating and cooling, and energy-related refuse-derived fuel production, both domestically and outside the United States.

Revenues from operating segments not included previously are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include a company that

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

trades and markets natural gas throughout the United States; a company involved in nonregulated power and natural gas marketing activities throughout the United States; a company that invests in and develops cogeneration and energy-related projects; a company that is engaged in engineering, design construction management and other miscellaneous services; a company engaged in energy consulting, energy efficiency management, conservation programs and mass market services; an affordable housing investment company; a broadband telecommunications company; and several other small companies and businesses.

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

directly assigned wherever applicable;

allocated based on cost causation allocators wherever applicable; and

allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1 to the Consolidated Financial Statements. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

Business Segments

	Electric Utility	Natural Gas Utility	NRG(b)	All Other(b)	Reconciling Eliminations	Consolidated Total
			(Thousands of dollars)			
2002						
Operating revenues from external customers(a)	$5,437,017	$1,397,799	$ 2,212,153	$ 405,839	$	$ 9,452,808
Intersegment revenues	987	4,949		165,732	(171,665)	3
Equity in earnings (losses) of unconsolidated affiliates(a)			68,996	2,565		71,561
Total revenues	$5,438,004	$1,402,748	$ 2,281,149	$ 574,136	$(171,665)	$ 9,524,372
Depreciation and amortization	$ 647,491	$ 92,868	$ 256,199	$ 40,871	$	$ 1,037,429
Financing costs, mainly interest expense	286,180	52,583	493,956	131,383	(46,022)	918,080
Income tax expense (credit)	301,875	53,831	(165,382)	(818,309)		(627,985)
Segment net income (loss)	$ 478,711	$ 98,517	$(3,464,282)	$ 715,140	$ (46,077)	$ (2,217,991)
2001						
Operating revenues from external customers(a)	$6,463,401	$2,051,199	$ 2,201,427	$ 397,895	$	$11,113,922
Intersegment revenues	978	4,501	1,859	178,111	(183,019)	2,430
Equity in earnings (losses) of unconsolidated affiliates(a)			210,032	7,038		217,070
Total revenues	$6,464,379	$2,055,700	$ 2,413,318	$ 583,044	$(183,019)	$11,333,422

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Electric Utility	Natural Gas Utility	NRG(b)	All Other(b)	Reconciling Eliminations	Consolidated Total
			(Thousands of dollars)			
Depreciation and amortization	$ 617,320	$ 92,989	$ 169,596	$ 26,398	$	$ 906,303
Financing costs, mainly interest expense	265,285	49,108	389,311	115,127	(52,055)	766,776
Income tax expense (credit)	351,181	41,077	28,052	(88,939)		331,371
Segment income (loss) before extraordinary items	$ 535,182	$ 81,562	$ 265,204	$ (56,879)	$ (40,390)	$ 784,679
Extraordinary items, net of tax	11,821			(1,534)		10,287
Segment net income (loss)	$ 547,003	$ 81,562	$ 265,204	$ (58,413)	$ (40,390)	$ 794,966
2000						
Operating revenues from external customers(a)	$5,704,683	$1,466,478	$1,670,774	$195,236	$	$9,037,171
Intersegment revenues	1,179	5,761	2,256	132,347	(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates(a)			139,364	43,350		182,714
Total revenues	$5,705,862	$1,472,239	$1,812,394	$370,933	$(137,962)	$9,223,466
Depreciation and amortization	$ 574,018	$ 85,353	$ 97,304	$ 10,071	$	$ 766,746
Financing costs, mainly interest expense	333,512	60,755	250,790	67,696	(59,780)	652,973
Income tax expense (credit)	261,942	36,962	86,903	(86,777)		299,030
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)					(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 526,828

(a)

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

NRG s international assets were $2,36 million and $3,199 million in 2002 and 2001, respectively. NRG s equity investments and projects outside the United States were $310 million and $417 million in 2002 and 2001, respectively.

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

(b)

NRG segment represents the consolidated results of NRG excluding the earnings attributable to minority shareholders of NRG prior to June 2002, when Xcel Energy acquired a 100 percent ownership in NRG.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All Other includes minority interest income (expense) related to NRG of $(13.6) million in 2002, $65.6 million in 2001, and $29.2 million in 2000. Also, in 2002 All Other includes income tax benefits related to Xcel Energy s investment in NRG of $706 million, as discussed in Note 11 to the Consolidated Financial Statements.

22. Summarized Quarterly Financial Data (Unaudited)

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized quarterly unaudited financial data is as follows:

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) 2002 results include special charges and unusual items in all quarters, as discussed in Note 2 to the Consolidated Financial Statements.

First-quarter results were decreased by $9 million, or 1 cent per share, for a special charge related to utility/ service company employee restaffing costs, and by $5 million, or 1 cent per share, for regulatory recovery adjustments at SPS.

Second-quarter results were decreased by $36 million, or 9 cents per share, for NEO-related special charges taken by NRG.

Third-quarter results (as restated) were decreased by $2.5 billion, or $5.97 per share, for special charges related to NRG asset impairments and financial restructuring, and were increased by $676 million, or $1.77 per share, due to estimated tax benefits related to Xcel Energy s investment in NRG.

Fourth-quarter results were decreased by $100 million, or 24 cents per share, for special charges related to NRG asset impairments and financial restructuring costs, and increased by $30 million, or $0.08 per share, due to revisions to the estimated tax benefits related to Xcel Energy s investment in NRG.

(b) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Note 2 to the Consolidated Financial Statements.

Second-quarter results were increased by $41 million, or 7 cents per share, for conservation incentive adjustments, and decreased by $23 million, or 4 cents per share, for a special charge related to post employment benefits.

Fourth-quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.

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

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

XCEL ENERGY INC. AND SUBSIDIARIES

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended Dec. 31, 2002, 2001 and 2000

		Additions			
	Balance at beginning of period	Charged to costs & expenses	Charged to other accounts	Deductions from reserves(1)	Balance at end of period
			(Thousands of dollars)		
Xcel Energy					
Reserve deducted from related assets:					
Provision for uncollectible accounts:					
2002	$37,487	$ 80,272	$10,129	$35,142	$ 92,746
2001	$41,350	$ 25,412	$ 6,487	$35,762	$ 37,487
2000	$13,043	$ 51,052	$ 3,953	$26,698	$ 41,350
Income tax valuation allowance, deducting From deferred tax assets in balance sheet:					
2002	$66,622	$1,010,425	$	$	$1,077,047
2001	$40,649	$ 25,973	$	$	$ 66,622
2000	$15,006	$ 25,643	$	$	$ 40,649

(1) Uncollectible accounts written off or transferred to other parties.

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UNAUDITED CONSOLIDATED PRO-FORMA FINANCIAL INFORMATION

ACCOUNTING FOR NRG ON THE EQUITY METHOD

Background

As discussed in Xcel Energy s Quarterly Report on Form 10-Q for Sept. 30, 2003, NRG voluntarily filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 14, 2003. As part of this action, the tentative settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG s creditors (the Settlement) was filed with the Bankruptcy Court for its consideration as a resolution of NRG s financial difficulties. If the court approves the terms of the Settlement, upon emergence from bankruptcy Xcel Energy will divest its ownership interests in NRG. However, pending the outcome of the bankruptcy proceeding, Xcel Energy will remain 100 percent owner of NRG but will not have sufficient control to continue consolidating NRG. During the period between NRG s filing for bankruptcy and its actual divestiture by Xcel Energy, Xcel Energy will report NRG as an equity investment under generally accepted accounting principles. Because such accounting requirements do not allow equity accounting until the period that includes the bankruptcy filing, Xcel Energy is providing investors with pro-forma information for historical periods presenting NRG under the equity method of accounting.

Pro-Forma Information

The following summary of unaudited pro-forma financial information for Xcel Energy gives effect to the change of accounting for NRG from consolidated financial reporting to the equity method of accounting. Under the equity method, NRG is not consolidated in Xcel Energy s financial statements but instead is reported as a single investment-related item (NRG Losses In Excess of Investment) on the Balance Sheet, and a single item (Equity in Losses of NRG) on the Statements of Operations. Because Xcel Energy s cumulative equity in NRG s losses to date exceeds the cumulative investments made in NRG, the investment-related balance sheet item is not an asset but is reported as a current liability.

The following pro-forma Statement of Operations is treated as if Xcel Energy had never consolidated NRG for financial reporting purposes. This unaudited pro-forma summarized financial information should be read in conjunction with the historical financial statements and related notes of Xcel Energy, which are included in the 2002 Annual Report on Form 10-K, and the Sept. 30, 2003, Quarterly Report on Form 10-Q. The unaudited pro-forma Statement of Operations information for the year-to-date period ended Sept. 30, 2002, assumes that NRG had been deconsolidated on Jan. 1, 2002, the beginning of the earliest period presented.

These summarized pro-forma amounts do not include any of the future financial impacts that may occur from NRG s filing for bankruptcy, or from implementing the Settlement. Also, the unaudited summarized pro-forma financial information does not necessarily indicate what Xcel Energy s financial position or operating results would have been if NRG had filed for bankruptcy (or had been divested) in the periods presented, and does not necessarily indicate future operating results of Xcel Energy (with or without NRG).

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XCEL ENERGY INC. AND SUBSIDIARIES

PRO-FORMA CONSOLIDATED STATEMENTS OF OPERATIONS

(Thousands of Dollars, Except Per Share Data)
For the Nine Months ended September 30, 2002

		Pro-Forma Adjustments for NRG		
	As Reported 9/30/2002(a)	Apply Equity Accounting(b)	Adjust Eliminations(c)	Pro-Forma Adjusted 9/30/2002(e)
Operating Revenues:				
Electric utility	$ 4,117,497			$ 4,117,497
Natural gas utility	937,814			937,814
Electric and natural gas trading margin	4,472			4,472
Nonregulated and other	1,937,902	(1,688,250)		249,652
Equity earnings from unconsolidated NRG affiliates	69,841	(69,841)		
Total operating revenues	7,067,526	(1,758,091)		5,309,435
Operating Expenses:				
Electric fuel and purchased power utility	1,650,961			1,650,961
Cost of natural gas sold and transported utility	559,347			559,347
Cost of sales nonregulated and other	1,002,379	(839,130)		163,249
Other operating and maintenance expenses utility	1,088,337			1,088,337
Other operating and maintenance expenses nonregulated	565,341	(487,335)		78,006
Depreciation and amortization	772,401	(188,038)		584,363
Taxes (other than income taxes)	255,143			255,143
Special charges	2,702,809	(2,677,801)		25,008
Total operating expenses	8,596,718	(4,192,304)		4,404,414
Operating income (loss)	(1,529,192)	2,434,213		905,021
Equity in losses of NRG(c)(d)		(3,123,211)		(3,123,211)
Minority interest in NRG losses	13,580			13,580
Interest and other income, net of nonoperating expenses	43,789	(19,148)		24,641
Interest charges and financing costs:				
Interest charges net of amounts capitalized	555,921	(295,611)		260,310
Distributions on redeemable preferred securities of subsidiary trusts	28,758			28,758
Total interest charges and financing costs	584,679	(295,611)		289,068
Income (loss) from continuing operations before income taxes	(2,056,502)	(412,535)		(2,469,037)
Income taxes (benefits)	(609,009)	153,206		(455,803)
Income (loss) from continuing operations(c)	$(1,447,493)	$ (565,741)	$	$(2,013,234)
Weighted average common shares outstanding (in thousands):				
Basic	376,565			376,565
Diluted	376,565			376,565

Earnings per share diluted:				
Income (loss) from continuing operations	$ (3.85)	$ (1.50)	$	$ (5.35)

See accompanying Notes to Pro-Forma Financial Information.

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XCEL ENERGY INC. AND SUBSIDIARIES

PRO-FORMA CONSOLIDATED STATEMENTS OF OPERATIONS

(Thousands of Dollars, Except Per Share Data)
For the Year ended December 31, 2002

		Pro-Forma Adjustments for NRG		Pro-Forma
	As Reported 12/31/2002(a)	Apply Equity Accounting(b)	Adjust Eliminations(c)	Adjusted 12/31/2002(e)
Operating revenues:				
Electric utility	$ 5,435,377			$ 5,435,377
Natural gas utility	1,397,800			1,397,800
Electric and natural gas trading margin	8,485			8,485
Nonregulated and other	2,611,149	(2,212,153)		398,996
Equity earnings from investments in affiliates	71,561	(68,996)		2,565
Total operating revenues	9,524,372	(2,281,149)		7,243,223
Operating expenses:				
Electric fuel and purchased power utility	2,199,099			2,199,099
Cost of natural gas sold and transported utility	851,987			851,987
Cost of sales nonregulated and other	1,361,466	(1,094,795)		266,671
Other operating and maintenance expenses utility	1,501,602			1,501,602
Other operating and maintenance expenses nonregulated	787,968	(665,886)		122,082
Depreciation and amortization	1,037,429	(256,199)		781,230
Taxes (other than income taxes)	318,641			318,641
Estimated gain/ loss on disposal of equity investments	207,290	(196,192)		11,098
Special charges	2,691,223	(2,656,093)		35,130
Total operating expenses	10,956,705	(4,869,165)		6,087,540
Operating income (loss)	(1,432,333)	2,588,016		1,155,683
Interest and other income, net of nonoperating expenses	43,987	(4,170)		39,817
Minority interest expense (income)	(17,071)	4,759		(12,312)
Equity in losses of NRG(d)		(3,464,282)		(3,464,282)
Interest charges and financing costs:				
Interest charges net of amounts capitalized	879,736	(493,956)		385,780
Distributions on redeemable preferred securities of subsidiary trusts	38,344			38,344
Total interest charges and financing costs	918,080	(493,956)		424,124
Income (loss) from continuing operations before income taxes	(2,289,355)	(391,239)		(2,680,594)
Income taxes (benefit)	(627,985)	165,382		(462,603)
Income (loss) from continuing operations	(1,661,370)	(556,621)		(2,217,991)
Weighted average common shares outstanding (in thousands):				
Basic	382,051			382,051
Diluted	382,051			382,051

Earnings (loss) per share basic and diluted:				
Income (loss) from continuing operations	$ (4.36)	$ (1.46)	$	$ (5.82)

See accompanying Notes to Pro-Forma Financial Information.

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NOTES TO PRO-FORMA FINANCIAL INFORMATION

The following notes provide additional information for the adjustments made to historical financial statements in determining the accompanying pro-forma financial information.

(a) As Reported amounts for nine months ended Sept. 30, 2002, were derived from the unaudited consolidated financial statements included in Xcel Energy s Quarterly Report on Form 10-Q for the period ended Sept. 30, 2003 (provided herewith).

(b) Pro-forma adjustments to As Reported amounts reflect (1) the elimination of NRG s revenues and expenses; and (2) equity accounting adjustments to reflect NRG s results of operations as a single income/expense item (Equity in Losses of NRG). In addition to NRG s amounts, application of the equity method also has resulted in the reclassification of the minority interest of NRG s stockholders other than Xcel Energy (prior to June 2002) on the Statement of Operations to be presented as a component of Equity in Losses of NRG.

(c) Pro-forma adjustments referred to in (b) above include the elimination of NRG s projects and operations that have been sold in 2002 or 2003, or were considered held-for-sale in those periods. Under the equity method of accounting being presented here on a pro-forma basis, the operating results of these NRG projects/operations are no longer presented as Discontinued Operations. This reclassification has increased the loss from Continuing Operations for the amounts previously reported as Discontinued Operations.

(d) The pro-forma adjustments to the Statement of Operations referred to in (b) above have adjusted Xcel Energy s pro-forma Equity Earnings from Unconsolidated NRG Affiliates to a net debit balance due to losses incurred by NRG. For pro-forma presentation purposes, we have not reported the equity in NRG losses as negative revenue, but instead have presented them as a nonoperating expense item.

(e) Divestiture of NRG is not assumed in pro-forma adjustments.

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(Thousands of Dollars, Except Per Share Data)

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2003	**2002**	**2003**	**2002**
		(As Restated)		**(As Restated)**
Operating revenues:				
Electric utility	$1,760,039	$ 1,556,942	$4,507,913	$ 4,117,497
Natural gas utility	183,112	138,268	1,122,797	937,814
Electric and natural gas trading margin	10,997	2,127	18,264	4,472
Nonregulated and other	103,576	748,025	326,347	1,937,902
Equity earnings from unconsolidated NRG affiliates		27,643		69,841
Total operating revenues	2,057,724	2,473,005	5,975,321	7,067,526
Operating expenses:				
Electric fuel and purchased power utility	816,554	618,442	2,050,148	1,650,961
Cost of natural gas sold and transported utility	103,144	58,115	757,988	559,347
Cost of sales nonregulated and other	73,707	411,420	221,079	1,002,379
Other operating and maintenance expenses utility	386,276	352,863	1,149,748	1,088,337
Other operating and maintenance expenses nonregulated	35,517	193,127	99,357	565,341
Depreciation and amortization	193,793	264,084	597,734	772,401
Taxes (other than income taxes)	84,746	87,538	248,087	255,143
Special charges (see Note 2)	2,980	2,628,160	11,752	2,702,809
Total operating expenses	1,696,717	4,613,749	5,135,893	8,596,718
Operating income (loss)	361,007	(2,140,744)	839,428	(1,529,192)
Equity in losses of NRG			(363,825)	
Minority interest in NRG losses				13,580
Interest and other income, net of nonoperating expenses (see Note 12)	21,590	9,790	30,690	43,789
Interest charges and financing costs:				
Interest charges net of amounts capitalized (includes other financing costs of $8,561, $13,270, $25,054 and $29,935, respectively)	105,074	166,343	320,737	555,921
Distributions on redeemable preferred securities of subsidiary trusts	2,621	9,586	21,773	28,758
Total interest charges and financing costs	107,695	175,929	342,510	584,679
Income (loss) from continuing operations before income taxes	274,902	(2,306,883)	163,783	(2,056,502)
Income taxes (benefit) (see Note 6)	(12,593)	(679,844)	39,837	(609,009)
Income (loss) from continuing operations	287,495	(1,627,039)	123,946	(1,447,493)
Income (loss) from discontinued operations, net of tax (see Note 3)		(577,001)	20,999	(565,741)
Net income (loss)	287,495	(2,204,040)	144,945	(2,013,234)
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180

Earnings (loss) available to common shareholders	$ 286,435	$ (2,205,100)	$ 141,765	$ (2,016,414)
Weighted average common shares outstanding (in thousands):				
Basic	398,751	397,405	398,728	376,565
Diluted	418,128	397,405	399,144	376,565
Earnings per share basic:				
Income (loss) from continuing operations	$ 0.72	$ (4.10)	$ 0.31	$ (3.85)
Discontinued operations		(1.45)	0.05	(1.50)
Earnings (loss) per share basic	$ 0.72	$ (5.55)	$ 0.36	$ (5.35)
Earnings per share diluted:				
Income (loss) from continuing operations	$ 0.69	$ (4.10)	$ 0.31	$ (3.85)
Discontinued operations		(1.45)	0.05	(1.50)
Earnings (loss) per share diluted	$ 0.69	$ (5.55)	$ 0.36	$ (5.35)

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(Thousands of Dollars)

	Nine Months Ended Sept. 30,	
	2003	**2002**
		(As Restated)
Operating activities:		
Net income (loss)	$ 144,945	$ (2,013,234)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	618,781	800,648
Nuclear fuel amortization	32,982	37,208
Deferred income taxes	(153)	(849,327)
Amortization of investment tax credits	(9,375)	(10,285)
Allowance for equity funds used during construction	(18,140)	(5,125)
Undistributed equity in losses (earnings) of unconsolidated affiliates, including NRG	362,424	(14,544)
Gain on sale of Viking Gas (2003) and nonregulated property (2002)	(35,799)	(6,785)
Non-cash special charges continuing operations (primarily asset impairment write-downs)		2,686,559
Non-cash asset impairment charges and disposal losses discontinued operations		616,829
Unrealized loss (gain) on derivative financial instruments	53,671	(46,514)
Change in accounts receivable	754	(32,686)
Change in inventories	19,678	32,981
Change in other current assets	(139,748)	146,473
Change in accounts payable	(131,521)	81,847
Change in other current liabilities	92,902	150,831
Change in other noncurrent assets	(38,141)	(166,962)
Change in other noncurrent liabilities	49,863	91,019
Net cash provided by operating activities	1,003,123	1,498,933
Investing activities:		
Utility capital/ construction expenditures	(638,886)	(696,092)
Nonregulated capital expenditures and asset acquisitions	(41,806)	(1,443,999)
Allowance for equity funds used during construction	18,140	5,125
Investments in external decommissioning fund	(42,669)	(47,141)
Equity investments, loans and deposits nonregulated projects	(14,544)	(108,383)
Proceeds from sale of discontinued operations and nonregulated property	122,493	40,465
Decrease in restricted cash	23,000	
Other investments net	(893)	(52,129)
Net cash used in investing activities	(575,165)	(2,302,154)
Financing activities:		
Short-term borrowings net	(379,814)	(172,047)
Proceeds from issuance of long-term debt	1,381,984	2,318,152
Repayment of long-term debt, including reacquisition premiums	(1,007,965)	(510,899)
Proceeds from issuance of common stock	833	570,242

Dividends paid	(227,455)	(420,560)
Net cash (used in) provided by financing activities	(232,417)	1,784,888
Net increase in cash and cash equivalents continuing operations	195,541	981,667
Net decrease in cash and cash equivalents reclassification of NRG to equity method	(385,055)	
Effect of exchange rate changes on cash	(16,061)	5,979
Cash and cash equivalents at beginning of period	901,273	261,305
Cash and cash equivalents at end of period	$ 695,698	$ 1,248,951

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	Sept. 30, 2003	Dec. 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 695,698	$ 901,273
Restricted cash		305,581
Accounts receivable net of allowance for bad debts of $26,792 and $92,745, respectively	710,525	961,060
Accrued unbilled revenues	316,943	390,984
Materials and supplies inventories at average cost	181,707	321,863
Fuel inventory at average cost	52,993	207,200
Natural gas inventories replacement cost in excess of LIFO: $87,701 and $20,502, respectively	156,609	147,306
Recoverable purchased natural gas and electric energy costs	193,926	63,975
Derivative instruments valuation at market	21,226	62,206
Current deferred income taxes (see Note 6)	563,653	
Prepayments and other	225,101	273,770
Current assets held for sale		101,950
Total current assets	3,118,381	3,737,168
Property, plant and equipment, at cost:		
Electric utility plant	17,126,762	16,516,790
Nonregulated property and other	1,672,453	8,411,088
Natural gas utility plant	2,474,398	2,603,545
Construction work in progress: utility amounts of $910,127 and $856,008, respectively	943,892	1,513,807
Total property, plant and equipment	22,217,505	29,045,230
Less accumulated depreciation	(9,537,934)	(10,303,575)
Nuclear fuel net of accumulated amortization: $1,091,513 and $1,058,531, respectively	90,199	74,139
Net property, plant and equipment	12,769,770	18,815,794
Other assets:		
Investments in unconsolidated affiliates	130,938	1,001,380
Notes receivable, including amounts from affiliates of $0 and $206,308, respectively	2,880	987,714
Nuclear decommissioning fund and other investments	765,125	732,166
Regulatory assets	741,815	576,403
Derivative instruments valuation at market	705	93,225
Prepaid pension asset	467,328	466,229
Goodwill net of accumulated amortization of $581 and $7,000, respectively	7,730	35,538
Intangible assets net of accumulated amortization of $3,196 and $18,900, respectively	58,213	68,210
Other	201,482	364,243
Noncurrent assets held for sale		379,772

Total other assets	2,376,216	4,704,880
Total assets	$18,264,367	$ 27,257,842

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	Sept. 30, 2003	Dec. 31, 2002
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 240,982	$ 7,756,261
Short-term debt	148,989	1,541,963
Accounts payable	684,360	1,404,135
Taxes accrued	355,106	267,214
Dividends payable		75,814
Derivative instruments valuation at market	47,563	38,767
NRG losses in excess of investment	927,414	
Other	389,348	749,521
Current liabilities held for sale		515,161
Total current liabilities	2,793,762	12,348,836
Deferred credits and other liabilities:		
Deferred income taxes	1,660,279	1,285,312
Deferred investment tax credits	159,922	169,696
Regulatory liabilities	597,426	518,427
Derivative instruments valuation at market	26,768	102,779
Benefit obligations and other	352,376	560,981
Asset retirement obligations (see Note 1)	1,008,534	
Customer advances	201,488	161,283
Minimum pension liability	128,053	106,897
Noncurrent liabilities held for sale		154,317
Total deferred credits and other liabilities	4,134,846	3,059,692
Minority interest in subsidiaries	5,433	34,762
Commitments and contingent liabilities (see Note 8)		
Capitalization:		
Long-term debt	6,411,736	6,550,248
Mandatorily redeemable preferred securities of subsidiary trusts	100,000	494,000
Preferred stockholders equity authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800	104,260	105,320
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2003 398,779,232; 2002 398,714,039	4,714,330	4,664,984
Total liabilities and equity	$ 18,264,367	$ 27,257,842

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND OTHER COMPREHENSIVE INCOME
(UNAUDITED)
(Thousands of Dollars, Except Share Data)

	Common Stock Issued						
	Number of Shares	Par Value	Capital in Excess of Par Value	Retained Earnings (Deficit)	Shares Held by ESOP	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Three months ended Sept. 30, 2003 and 2002							
Balance at June 30, 2002	396,874	$992,186	$4,019,732	$ 2,459,374	$(16,881)	$ (82,125)	$ 7,372,286
Net loss				(2,204,040)			(2,204,040)
Currency translation adjustments						(31,515)	(31,515)
After-tax net unrealized losses related to derivatives (see Note 10)						(25,036)	(25,036)
Unrealized gain on marketable securities						(1)	(1)
Comprehensive income for the period							(2,260,592)
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(1,060)			(1,060)
Common stock				(74,813)			(74,813)
Issuances of common stock net	1,774	4,435	15,274				19,709
Other				90		(8)	82
Repayment of ESOP loans					201		201
Balance at Sept. 30, 2002	398,648	$996,621	$4,035,006	$ 179,551	$(16,680)	$(138,685)	$ 5,055,813
Balance at June 30, 2003	398,732	$996,830	$3,888,803	$ (244,552)	$	$(257,064)	$ 4,384,017
Net income				287,495			287,495
Currency translation adjustments						(6,062)	(6,062)
After-tax net unrealized gains related to derivatives (see Note 10)						48,057	48,057
Unrealized loss on marketable securities						208	208
Comprehensive income for the period							329,698
Dividends declared:							
Cumulative preferred stock of Xcel Energy							
Common stock							
Issuances of common stock net	47	118	497				615

Balance at Sept. 30, 2003	398,779	$996,948	$3,889,300	$ 42,943	$	$(214,861)	$ 4,714,330

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY AND

OTHER COMPREHENSIVE INCOME
(UNAUDITED)
(Thousands of Dollars, Except Share Data)

	Common Stock Issued					Accumulated Other Comprehensive Income (Loss)	
	Number of Shares	Par Value	Capital in Excess of Par Value	Retained Earnings (Deficit)	Shares Held by ESOP		Total Stockholders Equity
Nine months ended Sept. 30, 2003 and 2002							
Balance at Dec. 31, 2001	345,801	$864,503	$2,969,589	$ 2,558,403	$(18,564)	$(179,454)	$ 6,194,477
Net loss				(2,013,234)			(2,013,234)
Currency translation adjustments						16,982	16,982
After-tax net unrealized losses related to derivatives (see Note 10)						(4,348)	(4,348)
Unrealized gain on marketable securities						(29)	(29)
Comprehensive income for the period							(2,000,629)
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(3,180)			(3,180)
Common stock				(362,601)			(362,601)
Issuances of common stock net	27,082	67,706	510,195				577,901
Acquisition of NRG minority common shares	25,765	64,412	555,222			28,150	647,784
Other				163		14	177
Repayment of ESOP loans					1,884		1,884
Balance at Sept. 30, 2002	398,648	$996,621	$4,035,006	$ 179,551	$(16,680)	$(138,685)	$ 5,055,813
Balance at Dec. 31, 2002	398,714	$996,785	$4,038,151	$ (100,942)	$	$(269,010)	$ 4,664,984
Net income				144,945			144,945
Currency translation adjustments						91,299	91,299
After-tax net unrealized losses related to derivatives (see Note 10)						(12,532)	(12,532)

Minimum pension liability						(24,837)	(24,837)
Unrealized loss on marketable securities						219	219
Comprehensive income for the period							199,094
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(1,060)			(1,060)
Common stock			(149,521)				(149,521)
Issuances of common stock net	65	163	670				833
Balance at Sept. 30, 2003	398,779	$996,948	$3,889,300	$ 42,943	$	$(214,861)	$ 4,714,330

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of Sept. 30, 2003, and Dec. 31, 2002; the results of its operations and stockholders equity for the three and nine months ended Sept. 30, 2003 and 2002; and its cash flows for the nine months ended Sept. 30, 2003 and 2002. Due to the seasonality of Xcel Energy s electric and natural gas sales and variability of nonregulated operations, such interim results are not necessarily an appropriate base from which to project annual results.

The accounting policies followed by Xcel Energy are set forth in Note 1 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2002. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K.

As discussed in Note 5 to the consolidated financial statements, during the second quarter of 2003, Xcel Energy changed its accounting and reporting of its subsidiary NRG Energy, Inc. (NRG) to the equity method for all 2003 financial results. Prior financial information continues to reflect NRG as a consolidated entity. See Note 5 to the consolidated financial statements.

Results for the third quarter of 2002 reflect restatement of NRG asset impairments and certain financing transactions, as discussed in Note 16 to the consolidated financial statements. Xcel Energy also reclassified certain items in the 2002 statement of operations, statement of cash flows and balance sheet to conform to the 2003 presentation. These reclassifications had no effect on restated stockholders equity, net income or earnings per share as previously reported.

1. 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 below. 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 Accounting for the Effects of Certain Types of Regulation.

Utility Impact of Adopting SFAS No. 143 Asset retirement obligations were recorded for the decommissioning of two Northern States Power Company (NSP-Minnesota), a Minnesota corporation, nuclear generating plants, the Monticello plant and the Prairie Island plant. A liability was also recorded for 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 through June 2000.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

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

	Increase (decrease) in:		
	Plant Assets	Regulatory Assets	Long-Term Liabilities
	(Thousands of dollars)		
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	
Reclassify pre-adoption accumulated depreciation approved by regulators	662,411	(662,411)	
Net impact of SFAS No. 143 on balance sheet	$ 682,497	$ 179,871	$862,368

A reconciliation of the beginning and ending aggregate carrying amount of NSP-Minnesota s asset retirement obligations recorded under SFAS No. 143 is shown in the table below for the nine months ended Sept. 30, 2003.

	Beginning Balance Jan. 1, 2003	Liabilities Incurred	Liabilities Settled	Accretion	Revisions To Prior Estimates	Ending Balance Sept. 30, 2003
	(Thousands of Dollars)					
Steam plant retirement	$ 2,725	$	$	$ 101	$	$ 2,826
Nuclear plant decommissioning	859,643			42,380	103,685	1,005,708
Total liability	$862,368	$	$	$42,481	$103,685	$1,008,534

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 recognized 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 in accumulated depreciation 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 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 Minnesota Public Utilities Commission (MPUC) in August 2003. The revised estimates resulted in an increase of $104 million to both the regulatory asset and the long-term liability, 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, as discussed in Note 14 to the consolidated financial statements.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

Pro-forma net income and earnings per share have not been presented for the years 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 $844 million as of Sept. 30, 2003, including external nuclear decommissioning investment funds and internally funded amounts.

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 Generally Accepted Accounting Principles (GAAP) liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates 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 estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 71 that are accrued in accumulated depreciation, are as follows at Jan. 1, 2003:

	(Millions of Dollars)
NSP-Minnesota	$304
NSP-Wisconsin	70
PSCo.	329
SPS	97
Cheyenne Light, Fuel & Power Co.	9
Total Xcel Energy	$809

2. Special Charges

Special charges included in Operating Expenses include the following:

	Three Months Ended		Nine Months Ended	
	Sept. 30, 2003	Sept. 30, 2002	Sept. 30, 2003	Sept. 30, 2002
	(Thousands of Dollars)			
NRG asset impairments and restructuring costs	$	$2,500	$	$2,556
NRG losses from equity investment disposals		117		122
Other investment disposal losses		11		11
Holding company costs related to NRG	3		12	
Regulatory recovery adjustment				5
Restaffing				9
Total special charges	$ 3	$2,628	$ 12	$2,703

Holding Company Costs (2003) During the first nine months of 2003, the Xcel Energy holding company incurred approximately $12 million for charges related to NRG s financial restructuring, including $3 million in the third quarter of 2003.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

NRG Special Charges (2002) In the second quarter of 2002, NRG expensed pretax charges of $36 million, or 6 cents per share, related to its NEO projects and $20 million, or 4 cents per share, for expected severance and related benefits. Additional severance accruals of $6 million, or 1 cent per share, were made in the third quarter of 2002. Through Sept. 30, 2002, severance costs had been recognized for all employees who had been terminated as of that date. Another $12 million, or 2 cents per share, of other NRG restructuring costs were recorded in the third quarter of 2002, including financial advisors, legal advisors and consultants. In addition, NRG also recorded a $16 million charge to income in the third quarter of 2002, for a decrease in the value of a remarketing option.

Due to financial difficulties (as discussed in Xcel Energy s 2002 Annual Report on Form 10-K), NRG s continuing operations incurred $2.6 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 in the third quarter of 2002, included write-downs of $2.2 billion for projects in development, $265 million for operating projects and $117 million for equity investments.

As discussed further in Note 5 to the consolidated financial statements, all of NRG s results for 2003 are reported in a single line item, Equity in Losses of NRG, due to the deconsolidation of NRG as a result of its bankruptcy filing in May 2003. NRG s 2003 results do reflect some effects of asset impairments and restructuring costs, which are discussed in Note 5 to the consolidated financial statements, but are not presented as a special charge in 2003.

Regulatory Recovery Adjustment (2002) During the first quarter of 2002, a wholly owned subsidiary of Xcel Energy, Southwestern Public Service (SPS), wrote off approximately $5 million, or 1 cent per share, of restructuring costs relating to costs incurred to comply with legislation requiring a transition to retail competition in Texas, which was subsequently amended to delay the required transition.

Utility Restaffing (2002) During the fourth quarter of 2001, Xcel Energy recorded an estimated liability for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. In the first quarter of 2002, the identification of affected employees was complete and additional pretax special charges of $9 million, or approximately 1 cent per share, were expensed for the final costs of the utility-related staff consolidations. All 564 of accrued staff terminations have occurred.

The following table summarizes the activity related to accrued restaffing special charges for the first nine months of 2003:

	Dec. 31, 2002 Liability*	Adjustments To Liabilities**	Payments	Sept. 30, 2003 Liability*
		(Millions of Dollars)		
Employee severance and related costs NRG	$ 18	$ (18)	$	$
Employee severance and related costs utility and service company	13		(10)	3
Total accrued special charges	$ 31	$ (18)	$ (10)	$ 3

* Reported on the balance sheet in other current liabilities and in postretirement and other benefit obligations at Dec. 31, 2002, and as other current liabilities at Sept. 30, 2003.

** The deconsolidation of NRG in 2003 has eliminated this liability from Xcel Energy s financial reporting (see Note 5).

Other (2002) During the third quarter of 2002, Xcel International disposed of its remaining interest in Yorkshire Power LLC in the United Kingdom, resulting in a pre-tax loss of $11.1 million and an after-tax loss of $8.3 million, or 2 cents per share.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

3. Discontinued Operations

NRG

During 2002, NRG entered into agreements to dispose of four consolidated international projects and one consolidated domestic project. Sales of four of the projects closed during 2002 (Bulo Bulo, Csepel, Entrade and Crockett Cogeneration) and one project (Killingholme) was sold in January 2003. In addition, NRG has also committed to a plan to sell a sixth project (Hsin Yu).

For 2002, these projects meet the requirements of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets for discontinued operations reporting and, accordingly, operating results and estimated gains or losses on disposal of these projects have been reclassified to discontinued operations for the 2002 periods. Summarized results of operations of NRG discontinued operations for 2002 were as follows:

	Three Months Ended Sept. 30, 2002	Nine Months Ended Sept. 30, 2002
	(Thousands of Dollars)	
Operating revenues	$ 184,733	$ 543,027
Operating and other expenses	(162,690)	(499,864)
Asset impairment charges	(599,732)	(599,732)
Pretax loss from discontinued operations	(577,689)	(556,569)
Income taxes	(8,111)	(7,925)
Loss from discontinued operations	(569,578)	(548,644)
Pretax loss from disposal	(7,423)	(17,097)
Net loss from discontinued operations	$(577,001)	$(565,741)

As of Jan. 1, 2003, Xcel Energy has reclassified all of its reporting of NRG to the equity method, as discussed in Note 5 to the consolidated financial statements. Under the equity method used for 2003 reporting, NRG s discontinued operations are combined with NRG s continuing operations and reported as a single item, Equity in Losses of NRG, within Xcel Energy s earnings from continuing operations. In addition, the assets and liabilities of these discontinued NRG projects as of Dec. 31, 2002, have been reclassified to the held-for-sale category and are reported separately from assets and liabilities of continuing operations for that period.

Xcel Energy reports in its 2002 discontinued operations only those NRG projects classified as discontinued as of May 14, 2003, the date of NRG s bankruptcy filing. NRG s reclassification of its discontinued operations subsequent to that date will not affect Xcel Energy reporting.

Viking Gas

In January 2003, Xcel Energy sold Viking Gas Transmission Co. and its interests in Guardian Pipeline, LLC for net proceeds of $124 million, resulting in a pretax gain of $36 million ($21 million after tax, or 5 cents per share). This gain has been reported in discontinued operations. Other quarterly and year-to-date operating results of Viking Gas and Guardian in 2003 and 2002, and Viking Gas assets and liabilities as of Dec. 31, 2002, were not reclassified to discontinued operations and assets and liabilities held-for-sale, respectively, due to immateriality.

4. NRG Financial Restructuring and Bankruptcy Filing

Since mid-2002, NRG has experienced severe financial difficulties, resulting primarily from lower prices for power and declining credit ratings. These financial difficulties have caused NRG to, among other things, fail to make payments of interest and/or principal aggregating over $400 million on outstanding indebtedness of approximately $4 billion and incur asset impairment charges and other costs in excess of $3 billion for the

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year ended Dec. 31, 2002. These asset impairment charges include write-offs for anticipated losses on sales of several NRG projects as well as anticipated losses related to projects to which NRG has stopped funding.

NRG Financial Restructuring In August 2002, NRG began the preparation of a comprehensive business plan and forecast. The business plan detailed the strategic merits and financial value of NRG s projects and operations. It also anticipated that NRG would function independently from Xcel Energy. NRG management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations would be insufficient to service recourse debt obligations. Based on this information and in consultation with Xcel Energy and a financial advisor, NRG prepared and submitted a restructuring plan in November 2002 to various lenders, bondholders and other creditor groups (collectively, NRG s Creditors) of NRG and its subsidiaries.

On March 26, 2003, Xcel Energy s board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against Xcel Energy, including claims related to the support and capital subscription agreement between Xcel Energy and NRG dated May 29, 2002 (Support Agreement). The principal terms of the settlement are as follows:

Xcel Energy would pay up to $752 million to NRG to settle all claims of NRG against Xcel Energy, including all claims under the Support Agreement and claims of NRG creditors who release Xcel Energy under the NRG plan of reorganization described below.

$350 million (including $112 million payable to NRG s bank lenders) would be paid at or shortly following the effective date of the NRG plan of reorganization. It is expected that this payment would be made in early 2004.

$50 million also would be paid in early 2004, and all or any part of such payment could be made, at Xcel Energy s election, in Xcel Energy common stock.

Up to $352 million would be paid commencing on April 30, 2004, unless at such time Xcel Energy had 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.

$390 million of the up to $752 million of total Xcel Energy payments are contingent on receiving releases from NRG creditors. To the extent Xcel Energy does not receive a release from an NRG creditor, Xcel Energy s obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon Xcel Energy receiving voluntary releases from at least 85 percent of the unsecured claims held by NRG creditors, including releases from 100 percent of NRG s bank creditors. As a result, it is not expected that Xcel Energy s payment obligations would be reduced by more than approximately $60 million. Any reduction would come from the Xcel Energy payments becoming due commencing on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, 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 would be terminated or other arrangements would be made such that Xcel Energy has no further liability and any cash collateral posted by Xcel Energy would be returned. As of Oct. 31, 2003, no such cash collateral is posted.

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 will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of Jan. 31, 2003, will be reduced to $10 million. The $10 million agreed amount is to be satisfied upon the effective date of the NRG plan of reorganization, with an unsecured promissory note

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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 would not be reconsolidated with Xcel Energy or any of its other affiliates for tax purposes at any time after their March 2001 deconsolidation (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 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. Under the settlement agreement, NRG would 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.

Consummation of the settlement, including Xcel Energy s obligations to make the payments set forth above, is contingent upon, among other things, the following:

The effective date of the NRG plan of reorganization for the NRG voluntary bankruptcy proceeding occurring on or prior to Dec. 15, 2003;

The final plan of reorganization approved by the bankruptcy court and related documents containing terms satisfactory to Xcel Energy, NRG and various groups of the NRG creditors;

The receipt of releases in favor of Xcel Energy from holders of at least 85 percent of the general unsecured claims held by NRG s creditors (including releases from 100 percent of NRG s bank creditors); and

The receipt by Xcel Energy of all necessary regulatory and other approvals.

Since many of these conditions are not within Xcel Energy s control, Xcel Energy cannot state with certainty that the settlement will be effectuated. Nevertheless, Xcel Energy management believes at this time that the settlement will be implemented.

Based on the tax effect of an expected write-off of Xcel Energy s investment in NRG, Xcel Energy has recognized at Sept. 30, 2003, an estimate of $811 million for the expected tax benefits related to the write-off, as discussed in Note 6 to the consolidated financial statements.

Xcel Energy expects to claim a worthless stock deduction in 2003 on its investment in NRG. This would result in Xcel Energy having a net operating loss for the year for tax purposes. Under current law, this 2003 net operating loss could be carried back two years for federal income tax purposes. Xcel Energy expects to file for a tax refund of approximately $325 million in the first quarter of 2004. This refund is based on a two-year carryback, as allowed under current tax law. The previous refund estimate of $355 million, as disclosed in June 2003, was based, in part, on an estimated 2002 tax liability that was recently determined to be lower than expected. The $30-million difference was refunded to Xcel Energy in October 2003.

As to the remaining $486 million of expected tax benefits, Xcel Energy expects to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The timing of cash savings from the reduction in estimated tax payments would depend on Xcel Energy s taxable income.

NRG Voluntary Bankruptcy Petition On May 14, 2003, NRG and certain of its affiliates filed voluntary petitions in the United States Bankruptcy Court for the Southern District of New York for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither Xcel Energy nor any of Xcel Energy s other subsidiaries were included in the filing.

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 provide for payments by Xcel Energy to NRG and its creditors of up to $752 million. A plan support agreement, reflecting the settlement, has been signed by Xcel Energy, NRG, a holder of approximately 40 percent in principal amount of NRG s long-term

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

notes and bonds along with two NRG banks that serve as co-chairs of the global steering committee for the NRG bank lenders. The terms of the plan support agreement with NRG s major creditors are basically the same as the terms of the March 26, 2003, settlement discussed previously. This agreement will become effective upon execution by holders of approximately an additional 10 percent in principal amount of NRG s long-term notes and specified other noteholders and bondholders and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. At this time, it appears unlikely that the plan support agreement will receive the requisite signatures prior to the effective date of the reorganization. However it is expected that various settlement-related agreements incorporating the terms of the settlement, which will be exhibits or supplements to the plan of reorganization and would be subject to approval in connection with the confirmation of the plan of reorganization, would supercede the plan support agreement. If approved, these agreements would be expected to be executed when the plan of reorganization is confirmed.

As of Dec. 31, 2002, NRG had consolidated company wide (filing and non-filing entities combined) assets of $10.9 billion and liabilities of $11.6 billion.

The following is the proposed timeline for NRG to emerge from bankruptcy in 2003. Based on this schedule, the effective date of NRG s plan of reorganization would be on or before Dec. 15, 2003. We cannot assure that this timeline will be met, that the NRG plan of reorganization will be approved or that NRG will complete the proposed restructuring.

On Oct. 8, 2003, the Federal Energy Regulatory Commission (FERC) approved the transfer of NRG assets to NRG s creditors;

On Oct. 10, 2003, the SEC issued the necessary order under the Public Utility Holding Company Act of 1935 (PUHCA) regarding the bankruptcy filing of NRG, allowing NRG to proceed with the solicitation of approval from its creditors of its plan of reorganization;

On Oct. 14, 2003, the solicitation for approval of NRG s plan of reorganization commenced;

On Nov. 12, 2003, votes on the plan of reorganization and objections to the plan of reorganization are due;

On Nov. 21, and Nov. 24, 2003, confirmation hearings have been scheduled on NRG s plan of reorganization; and

Appeals to the NRG plan of reorganization must be filed within 10 days after the confirmation of NRG s plan of reorganization.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities, consolidate and pool the entities assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. In the event the settlement described above is not effectuated, Xcel Energy believes that any effort to substantively consolidate Xcel Energy with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims or other claims under piercing the corporate veil, alter ego, control person or related theories in the NRG bankruptcy proceeding. If a bankruptcy court were to allow substantive consolidation of Xcel Energy and NRG or if another court were to allow other related claims against Xcel Energy, it would have a material adverse effect on Xcel Energy.

Financial Impacts of NRG s Bankruptcy As a result of the bankruptcy filing on May 14, 2003, Xcel Energy has discontinued the consolidation of NRG retroactive to Jan. 1, 2003, and for the year 2003 and is reporting NRG results under the equity method of accounting. See Note 5 for further discussion of the impacts of deconsolidating NRG in 2003.

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Prior to NRG s bankruptcy filing on May 14, 2003, Xcel Energy had recognized NRG losses in excess of its investment in NRG, as discussed in Note 5 to the consolidated financial statements. Xcel Energy s exposure to NRG losses subsequent to its deconsolidation is limited under the equity method to Xcel Energy s financial commitments to NRG. The estimated financial commitment to NRG, based on the terms of the settlement agreement (discussed previously), includes total Xcel Energy settlement payments related to NRG of up to $752 million. NRG losses recognized in excess of the $752 million in settlement payments will be reversed and recognized as a non-cash gain upon NRG s emergence from bankruptcy. However, should the settlement agreement not ultimately be approved by NRG s creditors and/or the bankruptcy court, the amount of financial assistance committed to NRG could be different from those amounts, pending the ultimate resolution of NRG s bankruptcy. Prior to reaching the settlement agreement, Xcel Energy and NRG had entered into the Support Agreement in 2002 pursuant to which Xcel Energy agreed, under certain circumstances, to provide a $300 million contribution to NRG. Upon effectiveness of the NRG plan of reorganization, Xcel Energy s obligation under the Support Agreement would be terminated.

In addition to the effects of NRG s losses, Xcel Energy s operating results and retained earnings in 2003 could also be affected by future tax effects of any financial commitments to NRG, if such income tax benefits were considered likely to be realized in the foreseeable future. See Note 6 for further discussion of tax benefits related to Xcel Energy s investment in NRG.

The accompanying consolidated financial statements do not necessarily reflect future conditions or matters that may arise as a result of NRG s bankruptcy filing and its ultimate resolution. Pending the outcome of its voluntary bankruptcy petition, NRG remains subject to substantial doubt as to its ability to continue as a going concern.

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

5. Accounting for and Reporting of NRG

As discussed in Note 4 to the consolidated financial statements, on May 14, 2003, NRG filed a voluntary case to restructure its obligations under Chapter 11 of the U.S. Bankruptcy Code in the Bankruptcy Court in the Southern District of New York. In October 2003, NRG began soliciting its existing creditors for approval of a plan of reorganization based on a settlement agreement (also discussed in Note 4 to the consolidated financial statements), which contemplates payments by Xcel Energy of up to $752 million. If NRG s creditors and the bankruptcy court approve the NRG plan of reorganization as presented, Xcel Energy anticipates that its ownership interest in NRG will be completely divested to NRG s creditors. Xcel Energy cannot assure that the NRG plan of reorganization as proposed will be approved or that NRG will successfully complete the proposed restructuring.

Prior to NRG s bankruptcy filing, Xcel Energy accounted for NRG as a consolidated subsidiary. However, as a result of NRG s bankruptcy filing, Xcel Energy no longer has 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. As discussed in the next paragraph, after changing to the equity method, Xcel Energy is limited in the amount of NRG s losses subsequent to the bankruptcy date that it must record.

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In accordance with these limitations under the equity method, Xcel Energy has 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. As of Sept. 30, 2003, Xcel Energy had recognized NRG losses to the point where they exceeded the investment made in NRG by $858 million, $106 million more than the amount of the $752 million financial commitment to NRG under the pro-forma settlement agreement discussed previously. See the reconciliation to the reported investment in the table below. The losses recognized in excess of the financial commitment will be reversed and recognized as a non-cash gain upon NRG s emergence from bankruptcy. If the final amount of financial commitments changes as a result of bankruptcy proceedings, the level of equity in NRG losses recorded by Xcel Energy would also change accordingly at that time. Xcel Energy has reflected these excess losses as a negative investment on the accompanying balance sheet in other current liabilities, based on its expectation that NRG s plan of reorganization will take effect, and the settlement payments will be made, within 12 months of the bankruptcy filing.

At the time of NRG s bankruptcy filing, Xcel Energy s negative investment was greater than its financial commitment to NRG. Therefore, no NRG losses for the post-bankruptcy period have been recognized by Xcel Energy. Beginning with June 30, 2003, quarterly reporting (the first period that includes the bankruptcy filing date), Xcel Energy has reclassified the 2003 net operating results of NRG as equity in losses of NRG in the statement of operations retroactive to Jan. 1, 2003, as required under the accounting rules governing a mid-year change from consolidating a subsidiary to accounting for the investment using the equity method. However, the presentation of NRG in the historical financial statements as a consolidated subsidiary in 2002 and prior periods will not change from the prior presentation.

NRG s stockholders equity as of Sept. 30, 2003, can be reconciled to Xcel Energy s recorded investment in NRG as of that date and to the pro-forma investment in NRG, including expected effects of divesting NRG and implementing the settlement agreement, as follows:

	Sept. 30, 2003
	(Millions of Dollars)
Stockholder s deficit of NRG	$(1,531)
NRG losses not recorded by Xcel Energy*	542
Purchase accounting adjustments **	62
Xcel Energy s negative investment in NRG liability	(927)
Pro-forma adjustments to reflect divestiture of NRG and settlement terms:	
Reclassification of NRG s other comprehensive income	24
Reclassification of intercompany receivables to investment	45
Pro-forma negative investment in NRG	$ (858)
Losses recognized in excess of financial commitments	106
Level of estimated financial commitments to NRG	$ (752)

* These represent NRG losses incurred in the second and third quarters of 2003 that were in excess of the equity accounting limitations discussed previously.

** These relate to Xcel Energy s June 2002 purchase of NRG s minority shares and are not reflected in NRG s financial statements.

Xcel Energy s pro-forma negative investment in NRG of $858 million will be eliminated over time through the reversal of $106 million in excess losses upon NRG s emergence from bankruptcy and through $752 million of expected cash settlement payments as described in Note 4 to the consolidated financial statements.

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NRG s loss for the three and nine month periods ended Sept. 30, 2003, can be reconciled to Xcel Energy s recorded equity in losses of NRG as follows:

	3 Months Ended Sept. 30, 2003	9 Months Ended Sept. 30, 2003
	(Millions of dollars)	
Total NRG income (loss)	$ (285)	$ (906)
Losses (income) not recorded by Xcel Energy under the equity method	285	542
Equity in losses of NRG included in Xcel Energy results	$	$ (364)

NRG Summarized Financial Information The following is summarized financial information for NRG for the periods in 2003 during which NRG was not consolidated:

Results of Operations

	3 Months Ended Sept. 30, 2003	9 Months Ended Sept. 30, 2003
	(Millions of dollars)	
Operating revenues	$ 671	$ 1,772
Operating income (loss)	(242)	(602)
Net income (loss)	(285)	(906)

Financial Position

	Sept. 30, 2003
	(Millions of dollars)
Current assets	$ 1,644
Other assets	8,531
Total assets	$ 10,175
Current liabilities	$ 2,089
Other liabilities	9,617
Stockholder s equity	(1,531)
Total liabilities and equity	$ 10,175

6. Estimated Income Tax Benefits Related to Xcel Energy s Investment in NRG

During 2002, Xcel Energy recognized an initial estimate of the expected tax benefits of $706 million, based on a settlement agreement with the major NRG creditors, including an expected write-off of Xcel Energy s investment in NRG for tax purposes. This benefit was based on the estimated tax basis of Xcel Energy s cash and stock investments already made in NRG, and their expected deductibility for federal income tax purposes.

In late August 2003, Xcel Energy determined that the tax basis in NRG was greater than originally estimated and that additional state tax benefits were available related to its investment in NRG. Based on revised estimates, Xcel Energy recorded $105 million, or 25 cents per share, of additional tax benefits in the third quarter of 2003, which increased Xcel Energy s cumulative income tax benefits related to its investment in NRG to $811 million. Based on the expected timing of NRG s emergence from bankruptcy and the filing of 2003 tax returns and related carrybacks (as discussed in Note 4), approximately $564 million of these deferred tax benefits have been classified as a current asset at Sept. 30, 2003 to reflect refunds and estimated tax payment reductions expected in the 12 months after that date.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

In addition, the expected settlement payments of $752 million may generate additional tax benefits and be reflected once NRG s creditors approve the NRG plan of reorganization. Assuming all settlement payments are fully deductible, additional tax benefits of more than $260 million could be recorded at the time that such benefits are considered likely of realization based on a judgment as to when the settlement payments to NRG become probable for tax purposes.

7. Rates and Regulation

NSP-Minnesota Service Quality Investigations As previously reported, 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 basis with an annual true-up. On Aug. 4, 2003, the state agencies jointly filed with the MPUC a report issued by Fraudwise, an investigation firm engaged by the state agencies to investigate the validity of allegations involving the integrity of NSP-Minnesota s service quality reporting. The findings of the report indicated instances of inconsistency and misstatement in the record-keeping system, but noted that these instances of manipulation appear to have been limited to a small number of employees. NSP-Minnesota is continuing its internal review of these matters and has taken certain remedial and disciplinary actions to address the record-keeping deficiencies.

On Sept. 24, 2003, NSP-Minnesota and the state agencies announced that they had reached a settlement agreement that would be submitted to the MPUC for its approval. Among the provisions are:

- $1 million in refunds to Minnesota customers who have experienced the longest duration of outages, which have been accrued at Sept. 30, 2003;

- additional actions to improve system reliability in an effort to reduce outage frequency and duration. These actions will target the primary outage causes, including tree trimming and cable replacement. At least an additional $15 million, above amounts being currently recovered in rates, is to be spent in Minnesota on these outage prevention improvements by Jan. 1, 2005; and

- development of a revised service quality plan containing a standard for service outage documentation, new performance measures, new thresholds for current performance measures and a new structure for consequences that will result from failure to meet these performance measures.

NSP-Minnesota is currently negotiating the details of the revised service quality plan with the state agencies. The new service quality plan, or a report on the progress of the negotiations, is expected to be filed with the MPUC on Nov. 14, 2003.

In 2002, the South Dakota Public Utilities Commission (SDPUC) investigated Xcel Energy s service quality. In particular, the investigation focused on NSP-Minnesota operations in the Sioux Falls area. NSP-Minnesota committed to a number of actions to improve reliability, which are being implemented, and to provide an updated 10-year capacity plan to the SDPUC by the end of 2003. NSP-Minnesota is working to complete the commitments made last December relating to service quality in the Sioux Falls area. NSP-Minnesota also is working with the SDPUC to provide information and to answer inquiries regarding service quality. No docket has been opened.

Midwest Independent Transmission System Operator, Inc. (MISO) Electric Market Initiative (NSP-Minnesota and NSP-Wisconsin) On July 25, 2003, MISO filed proposed changes to its regional open access transmission tariff to implement a new Transmission and Energy Markets Tariff (TEMT) that would establish certain wholesale energy and transmission service rates based on locational marginal cost pricing (LMP) to be effective in 2004. NSP-Minnesota and NSP-Wisconsin presently receive transmission services from MISO for service to their retail loads and would be subject to the new tariff, if approved by the FERC. After numerous parties, including several states, filed protests to the proposal, MISO filed on Oct. 17, 2003, to withdraw the TEMT without prejudice to refiling. The FERC issued an order approving the withdrawal and provided guidance on MISO s proposals on Oct. 29, 2003. MISO is now starting the

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stakeholder consultation process to prepare and submit a revised TEMT in 2004. Management believes any new tariff, if approved by the FERC, could have a material effect on wholesale power supply or transmission service costs to NSP-Minnesota and NSP-Wisconsin.

FERC Investigation Against All Wholesale Electric Sellers/ California Refund Proceedings (PSCo) On June 25, 2003, the FERC issued a series of orders addressing the California electricity markets. Two of these were show cause orders. In the first show cause order, the FERC found that 24 entities may have worked in concert through partnerships, alliances or other arrangements to engage in activities that constitute gaming and/or anomalous market behavior. The FERC initiated the proceedings against these 24 entities requiring that they show cause why their behavior did not constitute gaming and/or anomalous market behavior. PSCo was not named in this order. In a second show cause order, the FERC indicated that various California parties, including the California Independent System Operator (CAISO), have alleged that 43 entities individually engaged in one or more of seven specific types of practices that the FERC has identified as constituting gaming or anomalous market behavior within the meaning of the CAISO and California Power Exchange tariffs. PSCo was listed in an attachment to that show cause order as having been alleged to have engaged in one of the seven identified practices, namely circular scheduling. Subsequent to the show cause order, PSCo provided information to the FERC staff showing PSCo did not engage in circular scheduling. On Aug. 29, 2003, the FERC trial staff filed a motion to dismiss PSCo from the show cause proceeding. Various California parties have opposed the motion to dismiss. They have also requested rehearing of the FERC s show cause orders contending that the FERC should have named PSCo in the show cause orders as an entity that had engaged in a load shift transaction and a partnership that constituted gaming. PSCo has answered both the request for rehearing and the California parties opposition to the FERC staff s motion to dismiss.

PSCo General Rate Case In May 2002, PSCo filed a combined general retail electric, natural gas and thermal energy base rate case with the Colorado Public Utilities Commission (CPUC) as required in the merger approval agreement with the CPUC to form Xcel Energy. On April 4, 2003, a comprehensive settlement agreement between PSCo and all but one of the intervenors was executed and filed with the CPUC, which addressed all significant issues in the rate case. In summary, the settlement agreement, among other things, provides for:

- annual base rate decreases 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 recovers 100 percent of prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates during 2003. This clause is projected to recover energy costs totaling approximately $216 million in 2003;
- a new electric commodity adjustment clause (ECA) for 2004-2006, 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.

In June 2003, the CPUC issued its initial written order approving the settlement agreement. The new rates were effective July 1, 2003. The CPUC issued its final decision in the rate case on Aug. 8, 2003. PSCo expects to file the rate design portion of the case on or before Dec. 8, 2003.

PSCo Fuel Adjustment Clause Proceedings Certain wholesale electric sales customers of PSCo filed complaints with the FERC in 2002 alleging PSCo had been improperly collecting certain fuel and purchased energy costs through the wholesale fuel cost adjustment clause included in their rates. The FERC consolidated these complaints and set them for hearing. The complainants filed initial testimony in late April 2003 claiming the improper inclusion of fuel and purchased energy costs in the range of $40 million to $50 million related to the periods 1996 through 2002. PSCo submitted answering testimony in June 2003. The complainants filed rebuttal testimony on Aug. 1, 2003, and current claims have been reduced, now estimated

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at approximately $30 million. In August 2003, PSCo reached agreements in principle with all of the complainants under which such claims, as well as issues those customers had raised in response to PSCo s wholesale general rate case filing (discussed below), were compromised and settled. Under the settlement agreements in principle, PSCo will make cash payments or billing credits to certain of the complaining customers totaling approximately $1.5 million. The settlements also provide for revisions to the base demand and energy rates filed in the PSCo wholesale electric rate case. PSCo and the other parties are negotiating the detailed settlement provisions, which are subject to FERC approval.

PSCo had a retail incentive cost adjustment (ICA) cost recovery mechanism in place for periods prior to 2003. The CPUC conducted a proceeding to review and approve the incurred and recoverable 2001 costs under the ICA. On July 10, 2003, a stipulation and settlement agreement was filed with the CPUC, which resolved all issues. Under the stipulation and settlement agreement, the recoverable costs for 2001 and 2002 will be reduced by $1.6 million. Additional evaluation of the 2002 recoverable ICA costs will be conducted in a future proceeding. The resulting impact on the reset of the allowed cost recovery and cost sharing under the ICA for 2002 was not significant. In addition, the stipulation and settlement agreement provides for a prospective rate design adjustment related to the maximum allowable natural gas hedging costs that will be a part of the electric commodity adjustment for 2004 and is expected to reduce 2004 rates by an estimated $4.6 million. The stipulation and settlement agreement was approved by the CPUC in September 2003.

At Sept. 30, 2003, PSCo has recorded its deferred fuel and purchased energy costs based on the expected rate recovery of its costs as filed in the above rate proceedings, without the adjustments proposed by various parties. Pending the outcome of these regulatory proceedings, we cannot at this time determine whether any customer refunds or disallowances of PSCo s deferred costs will be required other than as discussed above.

PSCo Wholesale General Rate Case On June 19, 2003, PSCo filed a wholesale electric rate case with the FERC, proposing to increase the annual electric sales rates charged to wholesale customers, other than Cheyenne Light Fuel & Power Co., a wholly owned subsidiary of Xcel Energy. On Aug. 1, 2003, PSCo submitted a revised filing correcting an error in the calculation of income tax costs. The revised filing requests an approximately $2 million annual increase with new rates effective in January 2004, subject to refund. As discussed above, in August 2003, PSCo reached a settlement in principle in this case and the separate wholesale fuel clause cases.

PSCo Electric Department Earnings Test Proceedings PSCo has filed with the CPUC its annual electric department earnings test reports for 2001 and 2002. In both years, PSCo did not earn above its allowed authorized return on equity and, accordingly, has not recorded any refund obligations. In the 2001 proceeding, the Office of Consumer Counsel has proposed that the $10.9 million gain on the sale of the Boulder Hydroelectric Project be excluded from 2001 earnings and that possible refund of the gain be addressed in a separate proceeding. On Oct. 31, 2003, the administrative law judge ruled the gain was appropriately included in the 2001 earnings, and it is reasonable to amortize the gain over four years. In the 2002 proceeding, the CPUC has opened a docket to consider whether PSCo s cost of debt has been adversely affected by the financial difficulties at NRG and, if so, whether any adjustments to PSCo s cost of capital should be made. The 2002 proceeding has been set for hearing in August 2004.

PSCo Gas Cost Prudence Review As previously reported, in May 2002, the staff of the CPUC filed testimony in PSCo s gas cost prudence review case, recommending $6.1 million in disallowances of gas costs for the July 2000 through June 2001 gas purchase year. On Feb. 10, 2003, the administrative law judge issued a recommended decision rejecting the proposed disallowances and approving PSCo s gas costs for the subject gas purchase year as prudently incurred. The CPUC upheld the finding that PSCo was prudent and reasonable in its handling of the Western Natural Gas default in January 2001.

PSCo Annual Gas Cost Adjustment Filing PSCo recovers the cost of natural gas that it purchases for its customers use through a gas cost adjustment mechanism in its gas rates filed with the CPUC. On Sept. 16, 2003, PSCo requested an $88.8-million increase in prices for its customers through its annual gas cost

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

adjustment filing to reflect higher current and forecasted costs of natural gas. The price increase was approved by the CPUC and went into effect on Oct. 1, 2003.

PSCo Capacity Cost Adjustment In October 2003, PSCo filed with the CPUC an application to recover approximately $31.5 million of incremental capacity costs through a purchased capacity cost adjustment (PCCA) rider beginning March 1, 2004. The purpose of the PCCA is to recover purchased capacity payments to third party power suppliers that will not be recovered in PSCo s current base electric rates or other recovery mechanism. In addition, PSCo has proposed to return to its retail customers 100 percent of any electric earnings in excess of its authorized rate of return on equity allowed in the last rate case, currently 10.75 percent. A decision by the CPUC is expected in 2004.

Home Builders Association of Metropolitan Denver (PSCo) In February 2001, Home Builders Association of Metropolitan Denver (HBA) filed a complaint with the CPUC seeking a reparations award of $13.6 million for PSCo s failure to update its gas extension policy construction allowances from 1996 to 2002 under its tariff. On Aug. 27, 2003, the CPUC issued a ruling with respect to this matter and on Sept. 24, 2003, adopted a written order in this proceeding. According to the CPUC decision, PSCo is to pay reparations to HBA members, including interest, based on a revised construction allowance for the period Feb. 24, 1999, through May 31, 2002. The level of reparations based on the revised construction allowance is not known at this time. However, management expects total reparations are likely to be less than $1.5 million. PSCo and HBA have both requested rehearing of the Aug. 27, 2003 CPUC order.

SPS Texas Fuel Reconciliation, Fuel Factor and Fuel Surcharge Applications In June 2002, SPS filed an application for the Public Utility Commission of Texas (PUCT) to retrospectively review the operations of the utility s electric generation and fuel management activities. In this application, SPS filed its reconciliation for electric generation and fuel management activities, totaling approximately $608 million, from January 2000 through December 2001. In May 2003, a stipulation was approved by the PUCT. The stipulation resolves all issues regarding SPS fuel costs and wholesale trading activities through December 2001. SPS will withdraw, without prejudice, its request to share in 10 percent of margins from certain wholesale non-firm sales. SPS will recover $1.1 million from Texas customers for the proposed sharing of wholesale non-firm sales margins. The parties agreed that SPS would reduce its December 2001 fuel under-recovery balances by $5.8 million. Including the withdrawal of proposed margin sharing of wholesale non-firm sales, the net impact to SPS deferred fuel expense, before tax, is a reduction of $4.7 million.

In May 2003, SPS proposed to increase its voltage-level fuel factors to reflect increased fuel costs since the time SPS current fuel factors were approved in March 2002. The proposed fuel factors are expected to increase Texas annual retail revenues by approximately $60.2 million. SPS also reported to the PUCT that it has undercollected its fuel costs under the current Texas retail fixed fuel factors. In the same May 2003 application, SPS proposed to surcharge $13.2 million and related interest for fuel cost underrecoveries incurred through March 2003. In June 2003, the administrative law judge approved the increased fuel factors on an interim basis subject to hearings and completion of the case. The increased fuel factors became effective in July 2003. In July 2003, a unanimous settlement was reached adopting the surcharge and providing for the implementation of an expedited procedure for revising the fixed fuel factors on a semiannual basis. The surcharge will be collected from customers over an eight-month period. In August 2003, the PUCT approved the settlement and the new proposed fuel cost recovery process and the surcharge became effective in September 2003. The Texas retail fuel factors will change each November and May based on the projected cost of natural gas. Revenues will continue to be reconciled to fuel costs in accordance with Texas law.

In July 2003, SPS filed a second fuel cost surcharge factor application in Texas to recover an additional $26 million of fuel cost under-recoveries accrued during April through June 2003. In August 2003, the parties to the case filed a stipulation resolving various issues. The stipulation provided approval of SPS modified request to surcharge $15.7 million for the months April 2003 and May 2003 over 12 months beginning with the November 2003 billing cycle. The stipulation was approved by the PUCT in October 2003.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

In November 2003, SPS submitted a third fuel cost surcharge factor application in Texas to recover an additional $25 million of fuel cost underrecoveries accrued during June through September 2003. If approved, the proposed surcharge will go into effect after the first surcharge is completed and will continue for 12 months beginning in May 2004. This case is pending review and approval by the PUCT.

SPS New Mexico Fuel Reconciliation and Fuel Factor Applications On May 27, 2003, a hearing examiner for the New Mexico Public Regulatory Commission (NMPRC) issued a recommended decision on SPS s fuel proceeding approving SPS utilizing a monthly fuel factor. SPS had been utilizing an annual fuel factor, which had allowed significant undercollections. The decision denied the intervenors request that all margins from off-system sales be credited to ratepayers. On Aug. 19, 2003, the NMPRC approved the hearing examiner s recommended decision. In accordance with NMPRC regulations, SPS must file its next New Mexico fuel factor continuation case no later than August 2005.

SPS New Mexico Billing Practice Investigation On Sept. 25, 2003, the NMPRC entered an order opening an investigation into estimated billing practices used to send estimated bills to approximately 9,500 customers for between two and five months. As part of the Sept. 25, 2003, order, the NMPRC also implemented temporary billing measures for customers whose bills were estimated. The temporary billing measures: (i) require SPS to apply the lowest fuel and purchased power cost adjustment factor that was applicable during the period when meters were being estimated, (ii) allow customers six months to pay bills in full without additional charges or disconnection, (iii) prohibit disconnection of service until Nov. 1, 2003, for any customer that received an estimated bill, (iv) require a written explanation of the fuel calculation used under the order and (v) order a report of the amount of fuel and purchased power costs foregone as a result of the interim relief, which amount will not be allowed to be recovered from customers. The proceeding has been referred to a hearing examiner.

TRANSLink Transmission Co., LLC (TRANSLink) In 2002, NSP-Minnesota filed for MPUC approval to transfer functional control of its transmission system to TRANSLink, a proposed independent transmission company. In June 2003, the MPUC held a hearing on the TRANSLink application. At the hearing, the MPUC deferred any decision and indicated NSP-Minnesota could submit a supplemental or revised application to explain certain recent changes to the proposal and to respond to a number of issues and questions posed by the MPUC advisory staff and other parties. On Nov. 3, 2003, NSP-Minnesota submitted a status report to the MPUC indicating the participants are evaluating the TRANSLink proposal in light of recent events and would provide a further report within 30 days. Similar filings in North Dakota and Wisconsin are not contested, but have not been approved.

In 2002, SPS filed for PUCT and NMPRC approval to transfer functional control of its electric transmission system to TRANSLink, of which SPS would be a participant. In March 2003, the Southwest Power Pool (SPP) and the MISO cancelled their planned merger to form a large mid-continent regional transmission organization (RTO). This development materially impacted SPS applications in Texas and New Mexico. SPS requested the cases be dismissed without prejudice while it evaluates possible RTO arrangements for the SPS system.

Xcel Energy is considering these developments, as well as the proceedings in process in other jurisdictions, to evaluate the future role of TRANSLink in providing transmission operations services for the Xcel Energy system. As of Sept. 30, 2003, Xcel Energy s subsidiaries had deferred approximately $5 million of TRANSLink-related costs based on anticipated recovery in future rates.

8. Commitments and Contingent Liabilities

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

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NSP-Minnesota Notice of Violation On Dec. 10, 2001, the Minnesota Pollution Control Agency (MPCA) 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. The MPCA based its notice of violation in part on an Environmental Protection Agency (EPA) determination that the replacement constituted reconstruction of an affected facility under the Clean Air Act s New Source Review requirements. On June 27, 2003, the EPA rejected NSP-Minnesota s request for reconsideration of that determination. The New Source Performance Standard for coal handling systems is unlikely to require the installation of any emission controls not currently in place on the plant. It may impose additional monitoring requirements that would not have material impact on NSP-Minnesota or its operations. In addition, the MPCA or EPA may impose civil penalties for violations of up to $27,500 per day per violation. NSP-Minnesota is working with the MPCA to resolve the notice of violation.

French Island (NSP-Wisconsin) On Oct. 20, 2003, the U.S. District Court in Madison, Wisconsin entered a consent decree settling the EPA s claims against NSP-Wisconsin related to the French Island generating plant, but denying any liability. The consent decree is now enforceable. On or before Nov. 19, 2003, NSP-Wisconsin will pay a civil penalty of $500,000.

Other Environmental Contingencies Xcel Energy and its subsidiaries have been or are currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties and through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense for such unrecoverable amounts in its consolidated financial statements.

Commodity Futures Trading Commission Investigation On June 17, 2002, the Commodity Futures Trading Commission (CFTC) issued broad subpoenas to Xcel Energy on behalf of its affiliates, including PSCo and NRG, calling for production, among other things, of all documents related to natural gas and electricity trading (June 2002, subpoenas). Since that time, Xcel Energy has produced documents and other materials in response to numerous more specific requests under the June 2002 subpoenas. Certain of these requests and Xcel Energy s responses have concerned so-called round-trip trades. By a subpoena dated Jan. 29, 2003, and related letter requests (January 2003 subpoena), the CFTC has requested that Xcel Energy produce all documents related to all data submittals and documents provided to energy industry publications. Also beginning on Jan. 29, 2003, the CFTC has sought testimony from 20 current and former employees and executives, and may seek additional testimony from other employees, concerning the reporting of energy transactions to industry publications. Xcel Energy has produced documents and other materials in response to the January 2003 subpoena, including documents identifying instances where Xcel Energy s e prime subsidiary reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions.

In June 2003, as a result of Xcel Energy s ongoing investigation of this matter, representatives of Xcel Energy met with representatives of the CFTC and the Office of the United States Attorney for the District of Colorado. Xcel Energy has determined that several e prime employees reported inaccurate trading information to one industry publication and may have reported inaccurate trading information to other industry publications. e prime ceased reporting to publications in 2002.

A number of energy companies have stated in documents filed with the FERC that employees reported fictitious natural gas transactions to industry publications. Several companies have agreed to pay between $3 million and $28 million to the CFTC to settle alleged violations related to the reporting of fictitious transactions. The CFTC has also brought a civil complaint against an energy company alleging false reporting and attempted market manipulation. In the complaint, the CFTC requests damages as well as an order directing the energy company to disgorge benefits received from the alleged illegal acts. These and other

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

energy companies are also subject to an order by the FERC placing requirements on natural gas marketers related to reporting, as well as a FERC policy statement regarding reporting of price indices. In addition, two individual traders from the companies that have been fined have been charged in criminal indictments with reporting fictitious transactions.

Xcel Energy continues to investigate this matter, and e prime and Xcel Energy have suspended and/or terminated several employees in connection with the reporting of inaccurate natural gas transactions to industry publications. Nevertheless, Xcel Energy believes that none of e prime s reporting to industry publications had any effect on the financial accounting treatment of any transaction recorded in Xcel Energy s books and records. However, Xcel Energy is unable to determine if any reporting of inaccurate trade information to industry publications affected price indices. Xcel Energy is cooperating in the CFTC investigation, but cannot predict the outcome of any investigation.

California Litigation As discussed previously, including a discussion in the Form 10-K for the period ending Dec. 31, 2002, California District Court Judge Robert H. Whaley dismissed both California lawsuits (State of California v. Dynegy, et al. and Public Utility District No. 1 of Snohomish County v. Xcel Energy, et al.) that named several power generators and power traders, including Xcel Energy, as defendants in multi-district litigation. In both lawsuits, it was alleged that defendants engaged in unfair competition, market manipulation and price fixing. Both lawsuits were dismissed based on a finding that the filed rate doctrine precluded federal court jurisdiction. These decisions have been appealed to the Ninth Circuit, which has scheduled oral arguments for later this year. Two separate class action lawsuits were also filed in Washington (Symonds v. Xcel Energy, et al.) and Oregon (Lodewick v. Xcel Energy, et al.) alleging unfair competition similar to those filed in California. Both lawsuits named Xcel Energy and NRG as defendants and have been voluntarily dismissed by the plaintiffs.

In addition, the California attorney general s office has informed PSCo that it may raise claims against PSCo under the California Business and Professions Code with respect to the rates that PSCo has charged for wholesale sales and PSCo s reporting of those charges to the FERC. PSCo has had preliminary discussions with the California attorney general s office and has expressed the view that the FERC is the appropriate forum for the concerns that the attorney general has raised.

St. Cloud Gas Explosion As discussed previously in the Form 10-K for the period ending Dec. 31, 2002, 25 lawsuits have been filed as a result of a Dec. 11, 1998, gas explosion in St. Cloud, Minn. that killed four persons (including two employees of NSP-Minnesota), injured several others and damaged numerous buildings. Most of the lawsuits name as defendants NSP-Minnesota, Xcel Energy s Seren subsidiary, Cable Constructors, Inc. (CCI) (the contractor that struck the marked gas line) and Sirti, an architectural/ engineering firm hired by Seren for its St. Cloud cable installation project. The court granted the plaintiffs request to amend the complaint to seek punitive damages against Seren and CCI. The plaintiffs brought a similar motion against NSP-Minnesota, which was subsequently denied by the court. On Nov. 11, 2003, court-ordered mediation was conducted. As a result of this mediation NSP-Minnesota reached a confidential settlement with a group of plaintiffs representing the most significant claims asserted against NSP-Minnesota. The settlements will be paid by NSP-Minnesota s insurance carrier. A trial date has not been set for the remaining lawsuits.

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

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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 extending an offer to meet to discuss the matter further.

Other Contingencies The circumstances set forth in Notes 16, 18 and 19 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2002, appropriately represent, in all material respects, the current status of other commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following are unresolved contingencies that are material to Xcel Energy s financial position:

NRG Bankruptcy or Insolvency Bankruptcy plan of reorganization (Notes 4 and 6 to the consolidated financial statements describe the current status of certain financial contingencies related to NRG);

Tax Matters Tax deductibility of corporate-owned life insurance loan interest;

Asset Valuation Recoverability of investment in underperforming nonregulated projects (Seren, Argentina); and

Guarantees See Note 9 to the accompanying consolidated financial statements for discussion of exposures under various guarantees.

9. Short-Term Borrowings, Long-Term Debt and Other Financing Instruments

Short-Term Borrowings

At Sept. 30, 2003, Xcel Energy and its subsidiaries had approximately $149 million of short-term debt outstanding at a weighted average interest rate of 4 percent.

Long-Term Debt

On Oct. 6, 2003, SPS issued $100 million of 6 percent, Series C Senior Notes due 2033 in a private placement to qualified institutional buyers. On Oct. 15, 2003, the proceeds were used to redeem $100 million, 7.85 percent Trust Originated Preferred Securities of its trust subsidiary, Southwestern Public Service Capital I.

On Oct. 2, 2003, NSP-Wisconsin issued $150 million of 5.25 percent first mortgage bonds due Oct. 1, 2018 in a private placement to qualified institutional buyers. The proceeds were used to repay short-term debt incurred to pay at maturity $40 million of 5.75 percent first mortgage bonds due Oct. 1, 2003 and to redeem $110 million of 7.25 percent first mortgage bonds. On Oct. 15, 2003, NSP-Wisconsin redeemed the $110 million of 7.25 percent first mortgage bonds, due March 1, 2023.

On Oct. 1, 2003, NSP-Minnesota redeemed a total of $13.7 million of pollution control bonds consisting of $5.45 million related to the Minneapolis Community Development Agency, $3.4 million related to the city of Mankato and $4.85 million related to the city of Red Wing.

Preferred Stock

The third quarter dividend on the cumulative preferred stock of Xcel Energy was not declared on Sept. 30, 2003, pending final determination of retained earnings as of that date. 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. Xcel Energy had requested authorization from the SEC to pay its third quarter dividend out of capital and unearned surplus. However, no such authorization has yet been received. Consequently,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

cumulative preferred stock dividends of approximately $1.1 million were in arrears at Sept. 30, 2003. Amounts per share in arrears were as follows:

Series of Cumulative Preferred Stock	Dividend per Share
$3.60	$ 0.90
$4.08	$ 1.02
$4.10	$ 1.025
$4.11	$ 1.0275
$4.16	$ 1.04
$4.56	$ 1.14

On Oct. 23, 2003, Xcel Energy declared the third quarter preferred stock dividends, based on the third quarter results, which indicated sufficient retained earnings were available to do so. The dividends were paid on Nov. 10, 2003, to preferred stock shareholders of record on Oct. 31, 2003.

Guarantees

Xcel Energy provides various guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. As of Sept. 30, 2003, Xcel Energy had the following amount of guarantees and exposure under these guarantees:

Subsidiary	Total Guarantee	Exposure under Guarantee
	(Millions of Dollars)	
NRG	$ 80	$ 5
e prime	165	10
Other subsidiaries	84	3
Total	$ 329	$ 18

Xcel Energy guarantees certain obligations for NRG s power marketing subsidiary, relating to power marketing obligations, fuel purchasing transactions and hedging activities and for e prime, relating to trading and hedging activities. See Note 4 to the consolidated financial statements for the potential treatment of these guarantees in the NRG bankruptcy proceeding.

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

In addition, Xcel Energy provides indemnity protection for bonds issued by subsidiaries. The total amount of bonds with this indemnity outstanding as of Sept. 30, 2003, was approximately $33 million, of which $6 million relates to NRG. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

Accounting Changes

SFAS No. 150 In May 2003, the FASB issued SFAS No. 150 Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity (SFAS No. 150). SFAS No. 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity, including:

- instruments that represent, or are indexed to, an obligation to buy back the issuer s shares, regardless of whether the instrument is settled on a net-cash or gross physical basis;
- mandatorily redeemable equity instruments;
- written options that give the counterparty the right to require the issuer to buy back shares; and
- forward contracts that require the issuer to purchase shares.

In November 2003, the FASB posted a staff position, which delayed the implementation of SFAS No. 150 indefinitely. On Sept. 30, 2003, SPS had a special purpose subsidiary trust with outstanding mandatorily redeemable preferred securities of $100 million consolidated in Xcel Energy s Consolidated Balance Sheets. As stated previously, these securities were redeemed on Oct. 15, 2003. PSCo and NSP-Minnesota redeemed Trust Originated Preferred Securities on June 30, 2003, and July 31, 2003, respectively, and SFAS No. 150 will not affect such securities.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46, requiring an enterprise s consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, consolidation has been required for only 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 that the enterprise has a controlling financial interest in. 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. Additionally, Xcel Energy is evaluating two other arrangements based on criteria in FIN No. 46, and it is likely that these arrangements will require consolidation.

As of Sept. 30, 2003, the assets of the affordable housing investments were approximately $146 million and long-term liabilities were approximately $78 million. Currently, investments of $61 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2002, Consolidated Balance Sheet. FIN No. 46 requires that for entities to be consolidated, the entities assets be initially recorded at their carrying amounts at the date the new requirement first applies. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to the Xcel Energy s balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative-effect adjustment of an accounting change. Xcel Energy plans to adopt FIN No. 46 when required in the fourth quarter of 2003. The impact of consolidating these entities is not expected to have a material impact on net income.

10. Derivative Valuation and Financial Impacts

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

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

	Three months ended Sept. 30, 2003	Three months ended Sept. 30, 2002
	(Millions of Dollars)	
Accumulated other comprehensive income (loss) related to cash flow hedges at July 1	$ (38.5)	$ 82.3
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	47.5	53.4
After-tax net realized (gains) losses on derivative transactions reclassified into earnings	(12.6)	(17.7)
Regulatory deferral of costs to be recovered*	12.9	0.9
Discontinuance of hedge NRG		(61.6)
Accumulated other comprehensive income related to cash flow hedges Sept. 30	$ 9.3	$ 57.3

	Nine months ended Sept. 30, 2003	Nine months ended Sept. 30, 2002
	(Millions of Dollars)	
Accumulated other comprehensive income related to cash flow hedges at Jan. 1	$ 22.1	$ 34.2
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	38.7	67.9
After-tax net realized (gains) losses on derivative transactions reclassified into earnings	(100.7)	(11.9)
Regulatory deferral of costs to be recovered*	17.2	1.3
Acquisition of NRG minority interest		27.4
Reversal of NRG forecasted transactions no longer probable	32.0	
Discontinuance of hedge NRG		(61.6)
Accumulated other comprehensive income related to cash flow hedges Sept. 30	$ 9.3	$ 57.3

* In accordance with SFAS No. 71 Accounting for the Effects of Certain Types of Regulations, certain costs/ benefits have been deferred as they will be recovered in future periods from customers.

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 Sept. 30, 2003, Xcel Energy had various commodity-related contracts deemed as cash flow hedges extending through 2009. Amounts deferred in Other Comprehensive Income 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

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resale. As of Sept. 30, 2003, Xcel Energy had net gains of $44.9 million accumulated in Other Comprehensive Income that are expected to be recognized in earnings 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.

Xcel Energy recorded losses of $0 million and $0.6 million related to ineffectiveness on commodity cash flow hedges during the three months ended Sept. 30, 2003 and 2002, respectively, and gains of $0 million and $0.4 million related to ineffectiveness on commodity cash flow hedges during the nine months ended Sept. 30, 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 $4.3 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 differential 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 Sept. 30, 2003, was $(5.6) million.

Hedges of Foreign Currency Exposure of a Net Investment in Foreign Operations

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 $1.0 million and $0.8 million associated with changes in the fair value of non-hedge, foreign currency derivative instruments for the three months and nine months ended Sept. 30, 2002, respectively.

In addition, Xcel Energy recorded losses of $0 and $2.3 million related to the discontinuance of hedge accounting for the three and nine months ended Sept. 30, 2003 and three and nine months ended Sept. 30, 2002, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

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 and its 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 normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented and exempted from the accounting and reporting requirements of SFAS No. 133.

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

Accounting Changes

SFAS No. 149 In April 2003, the FASB issued SFAS No. 149 Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS No. 149), which amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies the discussion around initial net investment, clarifies when a derivative contains a financing component and amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45. In addition, SFAS No. 149 also incorporates certain implementation issues of a derivative implementation group. The provisions of SFAS No. 149 have been applied to contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003.

SFAS No. 133 Implementation Issue No. C20 In June 2003, for purposes of determining the applicability of the normal purchases and normal sales scope exception, the FASB issued SFAS No. 133 Implementation Issue No. C20 as supplemental guidance to SFAS No. 133 Implementation Issue No. C11. The effective date of the implementation guidance of Issue No. C20 is during the fourth quarter of 2003 for Xcel Energy. Xcel Energy is currently in the process of reviewing and interpreting this guidance and does not currently anticipate any material adverse financial impact due to the implementation of Issue No. C20 guidance as a result of its ability to recover prudently-incurred purchased capacity costs from customers.

11. Segment Information

Xcel Energy has the following reportable segments: Regulated Electric Utility, Regulated Natural Gas Utility and its nonregulated energy business, NRG. Trading operations performed by regulated operating companies are not a reportable segment. Electric trading results are included in the Regulated Electric Utility segment and natural gas trading results are presented in All Other.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

	Regulated Electric Utility	Regulated Natural Gas Utility	NRG	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of Dollars)					
Three months ended Sept. 30, 2003						
Operating revenues from external customers	$1,770,875	$183,112	$	$103,737	$	$ 2,057,724
Intersegment revenues	269	6,359		16,620	(23,248)	
Equity earnings from unconsolidated NRG affiliates						
Total revenues	$1,771,144	$189,471	$	$120,357	$(23,248)	$ 2,057,724
Segment net income (loss)	$ 201,753	$ (7,262)	$	$105,003	$(11,999)	$ 287,495
Three months ended Sept. 30, 2002						
Operating revenues from external customers	$1,553,810	$138,961	$ 665,896	$ 87,232	$	$ 2,445,899
Intersegment revenues	281	(93)		(12,383)	11,658	(537)
Equity earnings from unconsolidated NRG affiliates			27,643			27,643
Total revenues	$1,554,091	$138,868	$ 693,539	$ 74,849	$ 11,658	$ 2,473,005
Segment net income (loss)	$ 200,538	$ (10,732)	$(3,055,396)	$674,915	$(13,365)	$(2,204,040)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

	Regulated Electric Utility	Regulated Natural Gas Utility	NRG	All Other	Reconciling Eliminations	Consolidated Total
Nine months ended Sept. 30, 2003						
Operating revenues from external customers	$4,523,363	$1,122,797	$	$329,161	$	$ 5,975,321
Intersegment revenues	830	9,907		60,551	(71,288)	
Equity earnings from unconsolidated NRG affiliates						
Total revenues	$4,524,193	$1,132,704	$	$389,712	$(71,288)	$ 5,975,321
Segment net income (loss)	$ 357,378	$ 53,051	$ (363,825)	$135,233	$(36,892)	$ 144,945
Nine months ended Sept. 30, 2002						
Operating revenues from external customers	$4,114,715	$ 937,751	$ 1,688,250	$256,249	$	$ 6,996,965
Intersegment revenues	782	663		67,903	(68,628)	720
Equity earnings from unconsolidated NRG affiliates			69,841			69,841
Total revenues	$4,115,497	$ 938,414	$ 1,758,091	$324,152	$(68,628)	$ 7,067,526
Segment net income (loss)	$ 404,157	$ 48,063	$(3,123,211)	$684,753	$(26,996)	$(2,013,234)

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

12. Detail of Interest and Other Income, net of Nonoperating Expenses

Interest and other income, net of nonoperating expenses, is comprised of the following:

	3 months ended Sept. 30,		9 months ended Sept. 30,	
	2003	2002*	2003	2002*
	(Thousands of Dollars)			
Interest income	$ 1,732	$11,834	$ 13,543	$31,332
Equity income (loss) in unconsolidated affiliates (other than NRG)	3,179	326	(963)	3,298
Other nonoperating income	7,718	508	20,968	22,050
Gain on sale of nonregulated assets	15,055		15,055	
Minority interest expense (other than NRG)	2	(1,560)	(827)	(3,222)
Other nonoperating expenses	(6,096)	(1,318)	(17,086)	(9,669)

Total interest and other income, net of nonoperating expenses	$21,590	$ 9,790	$ 30,690	$43,789

* Includes NRG activity.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

13. Common Stock and Incentive Stock Awards

Common Stock and Equivalents Xcel Energy has common stock equivalents consisting of convertible senior notes and options. Due to the losses experienced in 2002, these equivalents were antidilutive and were not incorporated in the common stock and equivalents calculation in 2002. The convertible senior notes were also antidilutive for the nine months ended Sept. 30, 2003.

The dilutive impacts of common stock equivalents affected earnings per share as follows for the three- and nine-month periods ending Sept. 30, 2003:

	Three months ended Sept. 30, 2003			Nine months ended Sept. 30, 2003		
	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
	(Shares and dollars in thousands, except per share amounts)					
Income from continuing operations	$287,495			$123,946		
Less: Dividend requirements on preferred stock	(1,060)			(3,180)		
Basic earnings per share:						
Income from continuing operations	286,435	398,751	$0.72	120,766	398,728	$0.31
Effect of dilutive securities:						
7.5% convertible notes	2,803	18,654				
Options		723			416	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$289,238	418,128	$0.69	$120,766	399,144	$0.31

Restricted Stock Units On March 28, 2003, the compensation and nominating committee of Xcel Energy s board of directors granted restricted stock units and performance shares under the Xcel Energy omnibus incentive plan approved by the shareholders in 2000. No stock options have been 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. If the TSR target is not met within four years, the grant will be forfeited. 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. Xcel Energy accrued approximately $9 million in the second quarter of 2003 and $6 million in the third quarter of 2003 of estimated compensation expense related to the 2.4 million restricted stock units awarded in 2003, based on an expectation that the TSR requirements will be met, if the quarter-end stock price and dividend payouts continue.

SFAS No. 148 In December 2002, the Financial Accounting Standards Board (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 to earnings and earnings per share is immaterial. Xcel Energy continues to account for its stock-based compensation plans under Accounting Principles Board (APB) Opinion No. 25 Accounting for Stock Issued to Employees, and does not plan at this time to adopt the voluntary provisions of SFAS No. 148. Even with full dilutive effects of stock equivalents, the impact of application of SFAS No. 148 would be immaterial to the financial results of Xcel Energy.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

14. Nuclear Fuel Storage Prairie Island Legislation

On May 29, 2003, the Minnesota Legislature enacted legislation, which will enable NSP-Minnesota to store at least 12 more casks of spent fuel outside the Prairie Island nuclear generating plant, allowing NSP-Minnesota to continue to operate the facility and store spent fuel there until its licenses with the NRC expire in 2013 and 2014. The legislation transfers from the state Legislature to the MPUC the primary authority concerning future spent-fuel storage issues and allows for additional storage of spent nuclear fuel in the event the NRC extends the licenses of the Prairie Island and Monticello nuclear generating plant and the MPUC grants a certificate of need for such additional storage without the requirement of an affirmative vote from the state Legislature. The legislation requires Xcel Energy 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. Nearly all of the cost increases to NSP-Minnesota from these required payments and funding commitments are expected to be recoverable in 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 Xcel Energy 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.

15. Pension Plan Change and Impacts

In April 2003, Xcel Energy amended certain of its retirement plans to provide the same level of benefits to all non-bargaining employees of its utility and service company operations. While this change did not have a material impact on 2003 costs for the affected pension and retiree health plans, the increased obligations resulting from the plan amendment did create a minimum pension liability, which was recorded in the second quarter of 2003. This additional pension obligation, recorded almost entirely at SPS, increased noncurrent liabilities by approximately $21 million and reduced Accumulated Other Comprehensive Income, a component of shareholders equity, by approximately $25 million (net of related deferred tax effects of $14 million) during the second quarter of 2003. The minimum pension liability adjustments also increased noncurrent intangible assets by approximately $41 million due to the recording of unamortized prior service costs, and reduced previously recorded prepaid pension assets accordingly.

16. NRG 2002 Restatement

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

the asset impairment charges for Bayou Cove Peaking Power LLC and Somerset Power LLC to be $126.5 million and $49.3 million, respectively.

Additionally, NRG identified two items that had been inappropriately recorded as of Sept. 30, 2002. These items were the inappropriate treatment of interest rate swap transactions as cash flow hedges and the decrease in the value of a bond remarketing option from the original price paid by NRG. The error correction for the interest rate swaps resulted in the recording of additional income of $61.6 million as of Sept. 30, 2002. The recognition of the decrease in the value of the remarketing option resulted in a charge to income of $15.9 million as of Sept. 30, 2002.

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

	As Previously Reported*		As Restated	
	Three Months Ended Sept. 30, 2002	Nine Months Ended Sept. 30, 2002	Three Months Ended Sept. 30, 2002	Nine Months Ended Sept. 30, 2002
	(Thousands of dollars, except per share amounts)			
Consolidated statements of operations:				
Special charges	$ 2,436,467	$ 2,511,116	$ 2,628,160	$ 2,702,809
Operating income (loss)	(1,949,051)	(1,337,499)	(2,140,744)	(1,529,192)
Interest charges	227,956	494,308	166,343	555,921
Income (loss) from continuing operations	(1,496,959)	(1,317,413)	(1,627,039)	(1,447,493)
Net income (loss)	(2,073,960)	(1,883,154)	(2,204,040)	(2,013,234)
Earnings (loss) available for common shareholders	(2,075,020)	(1,886,334)	(2,205,100)	(2,016,414)
Earnings (loss) per share from continuing operations: basic and diluted	$ (3.77)	$ (3.51)	$ (4.10)	$ (3.85)
Net earnings per share: basic and diluted	$ (5.22)	$ (5.01)	$ (5.55)	$ (5.35)

* Amounts previously reported include reclassifications of NRG operations, which became discontinued after Sept. 30, 2002 as discussed in Note 3 to the consolidated financial statements.

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Xcel Energy Inc.

Offer to Exchange

$195,000,000 3.40% Senior Notes, Series B due 2008
For Any and All Outstanding
$195,000,000 3.40% Senior Notes, Series A due 2008

Prospectus

November 14, 2003