XCEL ENERGY INC
Form S-1/A
May 14, 2003

Table of Contents

As filed with the Securities and Exchange Commission on May 14, 2003

Registration No. 333-103258

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2 to

Form S-1

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Xcel Energy Inc.

(Exact Name of Registrant as Specified in Its Charter)

MINNESOTA	**4931**	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

800 Nicollet Mall
Minneapolis, Minnesota 55402
(612) 330-5500

(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

WAYNE H. BRUNETTI	**RICHARD C. KELLY**
President and Chief Executive Officer	Vice President and Chief Financial Officer
Xcel Energy Inc.	Xcel Energy Inc.
800 Nicollet Mall	800 Nicollet Mall
Minneapolis, Minnesota 55402	Minneapolis, Minnesota 55402
(612) 330-5500	(612) 330-5500

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copy to:

ROBERT J. JOSEPH

Jones Day
77 West Wacker Drive
Chicago, Illinois 60601
(312) 269-4176

Approximate date of commencement of proposed sale to the public: From time to time after this registration statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. þ

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

The registrant hereby amends this registration statement on such date as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

Table of Contents

Xcel Energy Inc.

800 Nicollet Mall, Suite 3000

Minneapolis, Minnesota 55402-2023
(612) 330-5500

$230,000,000

7 1/2% Senior Convertible Notes

due 2007
and

Shares of Common Stock issuable upon conversion of the Notes.

We sold the notes in a private offering on November 21, 2002. Selling security holders may use this prospectus to resell their notes and the shares of common stock issuable upon conversion of their notes. The notes mature on November 21, 2007. The notes are convertible, at the option of the holder, at any time on or prior to maturity into shares of our common stock. The notes are convertible at a conversion rate of approximately 81.1359 shares of our common stock per $1,000 principal amount of notes, which is equal to a conversion price of $12.33 per share, subject to adjustment as described in the prospectus.

We will pay interest on the notes on May 21 and November 21 of each year, beginning on May 21, 2003. The notes will mature on November 21, 2007. Holders of the notes may require us to purchase some or all of the notes for cash upon a change of control, as described in this prospectus, at a price equal to 100% of the principal amount of the notes tendered plus accrued and unpaid interest.

We will make additional payments of interest, referred to in this prospectus as protection payments, on the notes in an amount equal to any portion of our per share dividends on our common stock that exceeds $0.1875 per quarter that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. Holders of the notes will not be entitled to any protection payment if the dividend triggering the protection payment causes an adjustment of the conversion rate.

The notes are unsecured and unsubordinated obligations and rank on parity in right of payment with all our existing and future unsecured and unsubordinated indebtedness. As of December 31, 2002, we had approximately $600 million of long-term debt outstanding in addition to the notes excluding long-term debt of our subsidiaries. There are currently no outstanding debt obligations junior to the notes. We are structured as a holding company and conduct substantially all of our business through our subsidiaries. The notes are effectively subordinate to all existing and future indebtedness and other liabilities of our subsidiaries.

The notes issued in the initial private placement are eligible for trading in the PORTAL System. We do not intend to list the notes on any other securities exchange or automated quotation system. Our common stock is traded on the New York Stock Exchange under the symbol XEL.

As of December 31, 2002, our subsidiaries had approximately $20.7 billion indebtedness and other liabilities outstanding.

Investing in the notes involves risks. You should consider carefully the risk factors described under the caption Risk Factors beginning on page 8 of this prospectus before investing in the notes.

Please read this prospectus carefully before investing and retain it for your future reference.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is May 14, 2003

TABLE OF CONTENTS

Table of Contents

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.

TABLE OF CONTENTS

Table of Contents

INFORMATION 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, or similar expressions, or when we discuss our strategy or plans, we are ma 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 our access to capital and the ability of us and our subsidiaries to obtain financing on favorable terms;
- business conditions in the 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 the rate structures, and affect the speed and degree to which competition enters the electric and gas markets;
- the higher risk associated with our nonregulated business compared with our regulated businesses;
- currency translation and transaction adjustments;
- risks related to the financial condition of NRG Energy, Inc., one of our wholly-owned subsidiaries including NRG s ability to reach agreements with its lenders and creditors to restructure its debt;
- risks associated with the California power market;
- 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, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business, and Notes to Consolidated Financial Statements included elsewhere in this prospectus.

Table of Contents

PROSPECTUS SUMMARY

The following summary is qualified in its entirety by and should be read together with the more detailed information and financial statements included in this prospectus. Because this is a summary, it may not contain all the information that may be important to you. You should read the entire prospectus before making an investment decision. When used in this prospectus, the terms Xcel Energy, we, our and us refer to Xcel Energy Inc. and its consolidated subsidiaries, unless otherwise specified.

Our Business

We are a public utility holding company with six 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;

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

Black Mountain Gas Company (BMG), an Arizona corporation, which serves approximately 9,300 customers in Arizona.

Our regulated businesses also include WestGas InterState Inc. (WGI), an interstate natural gas pipeline. Prior to January 2003, our regulated businesses included Viking Gas Transmission Company (Viking).

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. As a result of the exchange of shares of Xcel Energy 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.

In addition to NRG, our nonregulated subsidiaries include:

Utility Engineering (UE), which is involved in engineering, construction and design;

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

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

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

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

Xcel Energy International (XEI), an international independent power producer.

We are a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). We were incorporated in 1909 under the laws of Minnesota as Northern States Power

1

Table of Contents

Company. On August 18, 2000, we merged with New Century Energies, Inc. (NCE) 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.

Recent Developments

On November 7, 2002, our subsidiary, Xcel Energy Market Holdings Inc., reached an agreement to sell its wholly-owned subsidiary, Viking and Viking s ownership interest in Guardian Pipeline, L.L.C. (Guardian) to a subsidiary of Northern Border Partners, L.P. (NBP). The sale was completed on January 17, 2003 and Xcel Energy received net proceeds of $124 million.

On November 8, 2002, we issued $100 million principal amount of 8% senior convertible notes (the Prior Notes) pursuant to a Securities Purchase Agreement with Citadel Equity Fund Ltd., Citadel Credit Trading Ltd. and Jackson Investment Fund Ltd. (together, the Purchasers). A portion of the proceeds of our initial issue and sale of the notes offered pursuant to this prospectus were used to redeem the Prior Notes on November 25, 2002. Upon redemption of the Prior Notes, we entered into an agreement with the Purchasers granting them the right, exercisable at any time and from time to time through November 24, 2003, to purchase notes in a private placement that are identical (other than issuance date) to the notes offered pursuant to this prospectus in an aggregate principal amount equal to $57,500,000.

On November 21, 2002, we issued the notes covered by this prospectus to Merrill, Lynch, Pierce, Fenner and Smith Incorporated and Lazard Frères & Co. L.L.C. in a private transaction. We received net proceeds from the sale of the notes, after deducting the initial purchasers discount and our offering expenses of approximately $220 million. As described above, a portion of the net proceeds from the sale of the notes were used to redeem the Prior Notes. The remaining net proceeds have and will be used for other general corporate purposes, including working capital.

On January 22, 2003, we entered into a nine month credit facility with King Street Capital, L.P. and Perry Principals Investments LLC, pursuant to which we may borrow up to $100 million at an interest rate of 9% per annum. There are currently no amounts outstanding under this facility.

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 (Minnesota Bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. A hearing was held April 10, 2003 to consider the motion to dismiss no decision was made. In their petition, the petitioners sought recovery of severance and other benefits of approximately $28 million.

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

On 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. 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.

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

Table of Contents

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 as of the date of this prospectus were as follows:

We would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, 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 January 1, 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 on April 30, 2004, except to the extent that we had not received at such time tax refunds equal to $352 million associated with the loss on our investment in NRG. To the extent we had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of our payments are contingent on receiving releases from NRG creditors. To the extent we do not receive a release from 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 releases from at least 85 percent of the claims in various NRG creditor groups. 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 payment due on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guaranties or other credit support obligations incurred by us for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by us would be returned. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with us, any intercompany claims of us against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guaranty 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 from approximately $55 million as asserted by us 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 us or any of our 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 us. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss we expect to incur in connection with the write down of our investment in NRG.

On May 12, 2003, the Minnesota Bankruptcy Court granted NRG s motion to dismiss the involuntary chapter 11 petition against NRG.

On May 14, 2003, NRG and certain of NRG s U.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 among NRG, us 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, holders of approximately 40% 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. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly.

Table of Contents

The term of the settlement with NRG s major creditors are basically the same as previously reported. $350 million would be paid at or shortly following the effective date of the NRG plan of reorganization. Of this amount, $112 million will be paid to a specific group of NRG bank lenders. It is expected that this payment would be made prior to year-end 2003. An additional $50 million would be paid on January 1, 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 in the second quarter of 2004.

Consummation of the settlement is contingent upon, among other things, the following:

(i) The effective date of the NRG plan of reorganization occurring on or prior to December 15, 2003;

(ii) The final plan of reorganization approved by the Bankruptcy Court and related documents containing terms satisfactory to us, NRG various groups of the NRG creditors;

(iii) The receipt of releases in our favor from holders of at least 85 percent of the claims represented by NRG s creditors;

(iii) NRG shall have used its reasonable best efforts, with the support of various NRG creditors, to cause the entry of an order by the Bankruptcy Court for the NRG proceeding, no later than 45 days after the Petition Date, approving the NRG disclosure statement; and

(iv) Our receipt of all necessary regulatory and other approvals.

Since many of the required conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented.

Since many of these conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented.

Table of Contents

The Offering

Issuer	Xcel Energy Inc.
Notes Offered	$230,000,000 principal amount of 7 1/2% Convertible Senior Notes due 2007 (including $30,000,000 pursuant to the overallotment option exercised by the initial purchasers in full).
Maturity	November 21, 2007
Interest Payment Dates	7 1/2% per annum on the principal amount, payable semiannually on May 21 and November 21, beginning on May 21, 2003.
Dividend Protection	We will make additional payments of interest, referred to in this prospectus as protection payments, on the notes in an amount equal to any portion of our per share dividends on our common stock that exceeds $0.1875 per quarter that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. Holders of the notes will not be entitled to any protection payment if the dividend triggering the protection payment causes an adjustment to the conversion rate.
Conversion Rights	The notes are convertible, at the option of the holder, at any time on or prior to maturity into shares of our common stock at a conversion price of $12.33 per share, which is equal to a conversion rate of approximately 81.1359 shares of common stock per $1,000 principal amount of notes. The conversion rate is subject to adjustment. See Description of the Notes Conversion Rights.
Ranking	The notes are unsecured and unsubordinated obligations and rank on a parity in right of payment with all our existing and future unsecured and unsubordinated indebtedness. The indenture under which the notes are issued does not prevent us or our subsidiaries from incurring additional indebtedness, which may be secured by some or all of our assets, or other obligations. As of December 31, 2002, we had no secured indebtedness and our unsecured and unsubordinated indebtedness had been approximately $830 million. We are structured as a holding company and conduct substantially all of our business operations through our subsidiaries. The notes are effectively subordinated to all existing and future indebtedness and other liabilities and commitments of our subsidiaries. As of December 31, 2002, our subsidiaries had aggregate indebtedness and other liabilities of approximately $20.7 billion.
Change of Control	Upon a change of control event, each holder of the notes may require us to repurchase some or all of its notes for cash at a repurchase price equal to 100% of the principal amount of the notes plus accrued and unpaid interest. See Description of the Notes Change of Control Permits Purchase of Notes at the Option of the Holder.
Use of Proceeds	We will not receive any proceeds from the sale by any selling security holder of the notes or the common stock issuable upon conversion of the notes. See Use of Proceeds.
DTC Eligibility	The notes were issued in book-entry form and are represented by permanent global certificates without coupons deposited with a

Table of Contents

	custodian for and registered in the name of a nominee of The Depository Trust Company in New York, New York. Beneficial interests in the notes are shown on, and transfers will be effected only through, records maintained by The Depository Trust Company and its direct and indirect participants, and any such interest may not be exchanged for certificated securities, except in limited circumstances. See Description of the Notes Form, Denomination and Registration.
Trading	The notes issued in the initial private placement are eligible for trading in the PORTAL System. We do not intend to list the notes on any other national securities exchange or automated quotation system. Our common stock is traded on the New York Stock Exchange under the symbol XEL.
Risk Factors	See Risk Factors and the other information in this prospectus before deciding to invest in the notes.

Table of Contents

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, and our audited 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.

	Year ended December 31,		
	2002(1)	2001	2000
	(Thousands of dollars)		
Consolidated Statement of Operations Data:			
Operating revenue	$ 9,524,372	$ 11,333,422	$ 9,223,466
Operating (loss) income	$ (1,432,333)	$ 1,858,147	$ 1,479,199
Interest charges and financing costs	$ 918,080	$ 766,776	$ 652,973
Net (loss) income	$ (2,217,991)	$ 794,966	$ 526,828

	December, 2002(2)
	(Thousands of dollars)
Consolidated Balance Sheet Data:	
Total assets	$ 27,257,842
Short-term debt (including current maturities)(3)	$ 9,298,224
Long-term debt(3)	$ 6,550,248
Total debt	$ 15,848,472
Minority interest	$ 34,762
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000
Preferred stockholders equity	$ 105,320
Common stockholders equity	$ 4,664,984
Total capitalization (includes short-term debt and minority interests)	$ 21,147,538

(1) Results for 2002 include two significant items that 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) Actual capitalization amounts are as reported in our consolidated Statements of Capitalization, which include amounts reclassified to discontinued operations of NRG. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $445.7 million of short-term debt is reported as current liabilities held for sale and $0.1 million of long-term debt is noncurrent liabilities held for sale.

(3) Based on the defaults under certain NRG debt agreements, and NRG s lenders 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.

Table of Contents

Summary Pro Forma Financial Data

As discussed in the Recent Developments section, on May 14, 2003 NRG filed for bankruptcy protection. This bankruptcy filing will change the 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. See Unaudited Consolidated Pro-forma Financial Information on pages F-85 et seq. for additional information on the pro-forma adjustments made, and a reconciliation of historical financial data to pro-forma amounts.

		Year ended December 31, 2002(1)
		(Thousands of dollars)
Consolidated Statement of Operations Data:		
Operating revenue	$	7,243,223
Operating loss	$	1,155,683
Interest charges and financing costs	$	424,124
Net loss	$	(2,217,991)

		December, 2002(2)
		(Thousands of dollars)
Consolidated Balance Sheet Data:		
Total assets	$	16,347,781
Short-term debt (including current maturities)	$	1,074,922
Long-term debt	$	5,357,618
Total debt	$	6,432,540
Minority interest	$	4,922
Mandatorily redeemable preferred securities of subsidiary trusts	$	494,000
Preferred stockholders equity	$	105,320
Common stockholders equity	$	4,664,984
Total capitalization (includes short-term debt and minority interests)	$	11,701,766

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.5 billion), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

(2) 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.

Table of Contents

RISK FACTORS

You should carefully consider the risks described below as well as all of the information set forth in this prospectus before purchasing the notes.

The risks described in this section are those that we consider to be the most significant to your decision whether to invest in the notes. If any of the events described below occurs, our business financial condition or results could be materially harmed. In addition, we may not be able to make payments on the 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 most of its debt obligations and could be deemed to be insolvent. Many of its subsidiaries are also in default on their debt obligations and could be deemed to be insolvent. If these entities were the subject of voluntary or involuntary bankruptcy proceedings, their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of NRG or its subsidiaries. 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 notes.

At December 31, 2002, NRG had 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 non-recourse and limited recourse debt instruments of NRG. In addition, on November 6, 2002, lenders accelerated the approximately $1.1 billion of debt under a construction revolver financing facility, thereby rendering the debt immediately due and payable. Further, 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 (Minnesota Bankruptcy Court). Under the provisions of federal law, NRG has full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. A hearing was held on April 10, 2003 to consider the motion to dismiss. No decision was made. In their petition, the petitioners sought recovery of severance and other benefits of approximately $28 million.

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

On 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. 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.

In addition to the missed debt payments, a significant amount of NRG s debt and other obligations contain terms which 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 since July 26, 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.

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

Table of Contents

us and NRG dated May 29, 2002 (the Support Agreement). The settlement is subject to a variety of conditions, including definitive documentation. Under the terms of the settlement which is described in more detail elsewhere in this prospectus, we would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, including all claims under the Support Agreement.

Because many of the conditions to the settlement are not within our control, the settlement may not be effectuated. 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. NRG s creditors may not accept a consensual restructuring plan, and, in the interim, NRG s lenders and bondholders may exercise 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.

Pending the resolution of NRG credit contingencies and the timing of possible asset sales, a portion of NRG s long-term debt obligations have been classified as current liabilities on our consolidated balance sheet due to lenders having the ability to accelerate such debt within twelve months of the balance sheet date. In the event that NRG is unable to effect a restructuring of its debt and other obligations and is unable to obtain adequate financing on acceptable terms, there would be substantial doubt as to NRG s ability to continue as a going concern. In any event, whether or not NRG becomes subject to a bankruptcy proceeding, it is unlikely that we ultimately will own any equity interest in NRG. As of December 31, 2002, our proforma investment in NRG, calculated as if NRG were deconsolidated at that date, was a negative $625 million. As of December 31, 2002, the net equity of NRG Energy as reported was a deficit of approximately $696 million.

If NRG does become subject to a bankruptcy proceeding, NRG or its creditors could seek to substantively consolidate us with NRG. The equitable doctrine of substantive consolidation would permit a bankruptcy court to disregard the separateness of related entities; such as NRG and us, and 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. Substantive consolidation is an equitable remedy in bankruptcy that results in the pooling of assets and liabilities of the debtor and 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 Bankruptcy Code and there are no definitive rules as to when a court will order substantive consolidation. Courts agree, however, that substantial 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 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 or related theories, in an NRG bankruptcy proceeding, the bankruptcy court could resolve the issue in a manner adverse to us. One of the creditors of an NRG project already has filed involuntary bankruptcy proceedings against that project and has included claims against NRG and us. If a bankruptcy court were to allow substantive consolidation of us with NRG, it would have a material adverse effect on us and on our ability to make payments on our obligations, including the notes, and could ultimately cause us to seek to restructure under the protection of the bankruptcy laws.

Table of Contents

On May 12, 2003, the Minnesota Bankruptcy Court granted NRG s motion to dismiss the involuntary chapter 11 petition against NRG.

On May 14, 2003, NRG and certain of NRG s U.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 among NRG, us 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, holders of approximately 40% 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. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly. The term of the settlement with NRG s major creditors are basically the same as previously reported. See our discussion in Recent Developments above.

If our assets are substantively consolidated with those of NRG, or if we otherwise incur significant liabilities relating to NRG, we may not have sufficient resources to satisfy those claims, and it would adversely affect our ability to make payments on the notes.

If NRG enters or is placed in bankruptcy, a bankruptcy court may substantively consolidate us with NRG and make our assets available to satisfy NRG s obligations.

Even without substantive consolidation, however, we have certain other potential exposures to claims relating to NRG. In May 2002, we entered into a Support Agreement pursuant to which we agreed to provide up to $300 million to NRG under certain circumstances. We may be required to provide NRG with this $300 million.

We have also provided various guarantees and bond indemnities supporting certain of NRG s 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 December 31, 2002, the maximum amount stated in our guarantees of obligations of NRG was approximately $219.5 million. Our aggregate exposure on guarantees of obligations of NRG was approximately $96.3 million as of December 31, 2002.

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 past and future accruals for these employees. To the extent NRG is unable to contribute amounts necessary to fund these accruals, we would be required to do so. We expect to agree to make a $2 million funding contribution due by NRG to our plan in March 2003 and seek reimbursement from NRG for the payment, although it is unlikely that we would obtain such reimbursement.

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.

Certain NRG current or former employees also participate in various welfare plans, including retiree medical and life plans, maintained by us. We have also provided guarantees for specified NRG severance and employment payments. Benefits that we may be required to pay NRG current or former employees pursuant to these arrangements could, in the aggregate, be material if NRG were unable to pay them when due.

Table of Contents

NRG maintains a long-term incentive plan under which options for 2,914,839 of our shares are outstanding. Such options, which have a weighted average exercise price of $29.80, would become fully exercisable if a change of control (as defined in the plan) of NRG were to occur during or following bankruptcy proceedings. Of these options outstanding, none currently have an in-the-money spread.

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%), 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 and is eligible for re-inclusion in our consolidated group as of June 2002. It is likely, though not certain, that we will decide not to reconsolidate NRG for income tax purposes for 2002. 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 group. If the IRS looked to us to pay taxes not paid by NRG, we would exercise any legal rights that are available for recovery of the payment from NRG, including in any NRG bankruptcy proceeding. Amounts that we could be required to pay to the IRS could be material and we may not be able to recover such amounts from NRG.

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 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 Xcel Energy; Wayne H. Brunetti, chairman, president 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 and Rule 10b-5 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 rating and the status of our internal controls to monitor trading of its power. Since the filing of the lawsuit on July 31, 2002, several additional lawsuits were filed with similar allegations, one of which added claims on behalf a purported class of purchasers of two series of NRG 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 our credit agreements with lenders for cross-defaults in the event of a default by NRG; it adds as additional defendants Gary R. Johnson, General Counsel, Richard C. Kelly, president of Xcel Energy Enterprises, two former executive officers of NRG (David H. Peterson, Leonard A. Bluhm) and one current executive officer of NRG (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-defaults provisions) under Section 11 of the Securities Act. On August 15, 2002, a shareholder derivative action was filed in the same court as the class actions described above purportedly on our behalf, against our directors and certain present and former officers, citing essentially the same circumstances as the class actions and asserting breach of fiduciary duty. Subsequently, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota, against essentially the same defendants, focusing on alleged wrongful energy trading

Table of Contents

activities and asserting breach of fiduciary duty for failure to establish and maintain adequate accounting controls, abuse of control and gross mismanagement. In addition, complaints have been filed against us, certain of our present and former officers and directors and the members of our board of directors in the United States District Court for the District of Colorado under the Employee Retirement Income Security Act by participants in our 401(k) and ESOP plan, alleging breach of fiduciary duty in allowing or encouraging purchase, contribution and/or retention of our common stock in the plans, and misleading statements and omissions in that regard, and purporting to represent classes from as early as September 23, 1999 forward. If any one or combination of these cases results in a substantial monetary judgment against us or is settled on unfavorable terms, our profitability and liquidity could be materially adversely affected.

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

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 are dependent upon receipt of cash dividends and distributions or other transfers from NRG s subsidiaries and project affiliates. The debt agreements of NRG s subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of December 31, 2002, certain of NRG s subsidiaries and project affiliates are restricted from making cash payments to NRG: among others, Loy Yang, Killingholme, Energy Center Kladno, LSP Energy (Batesville), NRG South Central and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG. Crockett Cogeneration is also limited in its ability to make distributions to NRG and its other partners.

Many of the debt agreements of NRG s subsidiaries and project affiliates require the funding of debt service reserve accounts. Prior to the NRG downgrades, certain debt service reserve account funding requirements were satisfied by provision of a guarantee from NRG. Following the downgrade of NRG, those guarantees no longer qualified as acceptable credit support and the accounts were required to be funded with cash by NRG. The accounts were not funded with cash from NRG, and, after allowing for applicable cure periods, events of default were triggered under such project financings that allow the lenders to accelerate the project debt. NRG South Central Generating, NRG McClain, NRG MidAtlantic, Flinders, NRG Northeast Generating and Enfield are precluded from making payments to NRG due to unfunded debt service reserve accounts. During January 2003, ownership of the Killingholme and Brazos Valley projects was transferred to their lenders and NRG no longer has an interest in those projects.

Additional asset impairments may be recorded by NRG in periods subsequent to December 31, 2002, given the changing business conditions for NRG and the resolution of its pending restructuring plan. We are unable at this time to determine the possible magnitude of any additional NRG asset impairments, but they could be material.

For additional information regarding our ownership of NRG and its potential implications on us, see Notes 4 and 18 to our consolidated financial statements.

Risks related to our Liquidity and Access to the Capital Markets

Our credit ratings have been recently 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 notes could decline.

Our credit ratings and access to the capital markets have been significantly and negatively affected recently, and may be further affected in the future. As of December 31, 2002, our senior unsecured debt was rated BBB by Standard & Poor s, Baa3 (negative outlook) by Moody s and BB+, with negative outlook, by Fitch. As a result, our ability to access needed capital and bank credit has been limited, and our cost of capital has increased materially. 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.

Table of Contents

On June 24, 2002, Standard & Poor s lowered the short-term rating on our commercial paper to A-3 from A-2 and on July 30, 2002, Fitch withdrew our commercial paper rating. Our commercial paper is currently not rated by Moody s. Consequently, we do not currently have access to the commercial paper market and refinanced our outstanding commercial paper as it matured with borrowings under our credit facilities. As of December 31, 2002, and after giving effect to the repayment of the $400 million credit facility at maturity on November 8, 2002, we had no commercial paper outstanding and had borrowings of approximately $400 million under our five-year credit facility, which matures in November 2005.

Our cost of new borrowings to replace our commercial paper is greater than the historical cost of our commercial paper. As a result of our loss of access to the commercial paper market and the current lack of additional capacity under our credit facility, we are more dependent upon accessing the capital markets. Access to the capital markets on favorable terms will be affected 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, including NRG, 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, including NRG. Further adverse developments related to NRG s liquidity and its debt and other obligations described above, and the actions we take to address that situation, could have an adverse effect on our credit ratings and therefore our liquidity. Any lowering of the rating of the notes offered hereby would likely reduce the value of the notes.

We have provided various guarantees and bond indemnities supporting certain of our subsidiaries by guaranteeing the payment or performance by such 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 December 31, 2002, we had guarantees outstanding with a maximum stated amount of approximately $1,509 million and actual current aggregate exposure of approximately $446 million, which amount may vary over time.

On November 21, 2002 Moody s rated the notes Baa3 (negative outlook). If either Standard & Poor s or Moody s were subsequently 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.

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 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 recent events at NRG discussed above and the recent downgrades in our short-term ratings, we do not have access to the commercial paper market.

In addition, our $400 million revolving credit facility expired in November 2002, and we were not able to renew this facility on favorable terms. Consequently, we repaid the facility from funds from a new financing and from available cash. Our inability to obtain bank financing on favorable terms will limit our ability to contribute equity or make loans to our subsidiaries, including our regulated utilities, and may cause us to seek alternative sources of funds to meet temporary cash needs.

Furthermore, until the issues related to NRG are resolved, our access to the capital markets is likely to 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.

Table of Contents

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 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 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 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 authority from the SEC under PUHCA for various financing arrangements. One of the conditions of our original financing order was that our ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. During the quarter ended September 30, 2002, we were required to record significant asset impairment losses from sales or divestitures of NRG assets and businesses, from NRG s cancelling 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.

In anticipation of falling below the 30 percent level, we obtained authorization from the SEC under PUHCA to engage in certain financing transactions and intrasystem loans through March 31, 2003, so long as our ratio of common equity to total capitalization, on an as adjusted basis, is at least 24 percent. As of September 30, 2002, our common equity ratio, as adjusted, was at least 24 percent. Financings authorized by the SEC included the issuance of debt (including convertible debt) to refinance or replace a $400 million credit facility that expired on November 8, 2002, issuance of $483 million of stock (less amounts of long-term debt issued as part of the refinancing of the $400 million credit facility) and the renewal of guarantees for trading obligations of NRG s power marketing subsidiary. The SEC reserved jurisdiction over additional securities issuances by us through June 30, 2003, while our common equity ratio is below 30 percent. After June 30, 2003, our common equity ratio must be at least 30 percent in order to engage in financing transactions without additional approval of the SEC.

On December 20, 2002, we filed a revised request with the SEC seeking additional financing authorization to conduct our business as proposed during 2003. We are seeking an increase of $500 million in the amount of long-term debt and common equity we are authorized to issue from $2.0 billion to $2.5 billion. In addition, we proposed that our common equity, as reflected on our most recent Form 10-K or Form 10-Q and as adjusted to reflect subsequent events that affect capitalization, will be at least 30 percent of total consolidated capitalization, provided that in any event that we do not satisfy the 30 percent common equity standard, we may issue common stock. We further asked the SEC to reserve jurisdiction over the

Table of Contents

authorization for us and our subsidiaries to engage in any other financing transactions authorized under current SEC orders and in the instant request at a time that we do not satisfy the 30 percent common equity standard. We also requested that the SEC permit us 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. See discussion of dividend restrictions in Note 12 to the consolidated financial statements.

It is possible that we may be required to recognize further losses at NRG and that our common equity ratio may fall below the 24 percent level. As of December 31, 2002, our common equity ratio was below 24 percent. In addition, it is anticipated that for at least some period of time following March 31, 2003, our common equity ratio will be below 30 percent. If that occurs and we are unable to obtain additional relief from the SEC, we may not be able to issue securities, which could have a material adverse effect on our ability to make payments on the notes and otherwise meet our capital and other needs.

For additional information regarding our liquidity and capital resources, and the effect that the recent reductions in our credit ratings has 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

There may be changes in the regulatory environment that impair our ability to recover costs from our 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 operations including siting and construction of facilities, customer service and the rates that we can charge customers.

In light of the recent credit and liquidity events regarding NRG, we face enhanced scrutiny from our state regulators. On August 8, 2002, the MPUC asked for additional information related to the impact of NRG s financial circumstances on NSP-Minnesota. Subsequent to that date, several newspaper articles alleged concern about the reporting of service quality data and NSP-Minnesota s overall maintenance practices. In an order dated October 22, 2002, the MPUC opened an investigation into the accuracy of NSP-Minnesota s reliability records and to allow for further review of its maintenance and other service quality measures. The Minnesota Department of Commerce and Office of Attorney General have begun an investigation of these issues. There is no scheduled date for completion of these investigations. These investigations, and any attendant remedial actions, may materially and adversely affect the financial position and results of operations of NSP-Minnesota.

The events relating to NRG could also negatively impact the positions taken by the Colorado Public Utilities Commission (CPUC) in PSCo s pending and future rate proceedings, which could result in reduced recovery of our costs. In May 2002, PSCo filed a combined general retail electric, gas and thermal energy base rate case with the Colorado Public Utilities Commission (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:

- 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. This clause is projected to recover energy costs totaling approximately $216 million in 2003. The IAC originally went into effect on Jan. 1, 2003. The IAC rate was increased on May 1, 2003 by $93 million to recover the total anticipated energy costs for 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;

an authorized return on equity of 10.75 percent for electricity and 11.0 percent for natural gas and thermal energy.

Hearings on one settlement agreement were held in late April 2003. Management believes the CPUC will approve the settlement agreement and issue a final rate order during the second quarter, with new rates effective as discussed above. PSCo will now move to the phase II, rate design, portion of the case.

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. 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 notes.

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 Federal Energy Regulatory Commission 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 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 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, financial derivative instrument contracts do not eliminate the risk. Specifically, such risks include 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.

Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If 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. 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, models based on forward price curves are utilized. 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. On May 21, 2002, the FERC supplemented the May 8th request by ordering 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 that we had not engaged in so-called round trip electricity trading 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.

We also have received a subpoena from the SEC for documents concerning round trip trades in electricity and natural gas with Reliant Resources, Inc. 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. 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.

If it is 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. Xcel Energy and PSCo have been named in the California litigation and it is possible that we could be brought into the additional 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 results.

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 NRG, calling for production, among other things, of all documents related to natural gas and electricity trading (the June 17, 2002 subpoenas). Since that time, we have produced documents and other materials in response to

Table of Contents

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 January 29, 2003 subpoena), the CFTC has requested that we produce all documents related to all data submittals and documents provided to energy industry publications. We have produced documents and other materials in response to the January 29, 2003 subpoena, including a report identifying instances where our e prime subsidiary reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions. We believe this reporting did not affect the financial accounting treatment of any transaction recorded in e prime s books and records. Also beginning on January 29, 2003, the CFTC has sought testimony from twenty current and former employees, and may seek additional testimony from other employees and executives, concerning the reporting of energy transactions to industry publications. A number of energy companies have stated in documents filed with FERC that employees reported fictitious natural gas transactions to industry publications. Various other energy companies are also subject to a recent order by FERC placing requirements on natural gas marketers related to reporting. We and NRG are cooperating in the CFTC investigation, but cannot predict the outcome of any investigation.

We received a Notice of Violation from the United States Environmental Protection Agency 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 July 1, 2002, we received a Notice of Violation (NOV) from the United States Environmental Protection Agency (EPA) alleging violations of the New Source Review (NSR) requirements of the Clean Air Act 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. Although we believe we acted in full compliance with the Clean Air Act and NSR process, we cannot assure you that we will not be required to install additional emission control equipment at the facilities, which would require substantial capital expenditures, 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 EPA s initial information requests related to its plants in Minnesota. On May 22, 2002, EPA issued a follow-up information request to NSP-Minnesota seeking additional information regarding NSR compliance at its plants in Minnesota. NSP-Minnesota has responded to the follow-up request.

Our subsidiary, PSCo, has received a notice from the Internal Revenue Service (the 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. From time to time, 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. 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.

Table of Contents

After consultation with tax counsel, we believe that the IRS position is not supported by the tax law. Based on this assessment, PSCo continues to believe that the deduction of interest expense on the COLI policy loans is in full compliance with the tax law. For this reason and following consultation with our auditors, we have determined not to record any provision or reserve for income taxes or interest charges in connection with this matter. In addition, PSCo has continued to claim deductions for interest expense related to COLI policy loans on its income tax returns for taxable years after 1997, and intends to continue to challenge the IRS s proposed disallowance.

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 expenses related to these COLI policy loans, the tax and interest ultimately owed by us, should the IRS and state tax agencies ultimately prevail, will continue to increase over time.

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

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 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 consolidated financial statements.

Risks Related to the Notes

The notes are effectively subordinated to all existing and future indebtedness and liabilities of our subsidiaries.

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 notes are effectively subordinated to all existing and future indebtedness and other liabilities, including trade payables, of our subsidiaries.

As of December 31, 2002, our subsidiaries had outstanding indebtedness and other liabilities of approximately $20.7 billion. Some of these liabilities are secured by the assets of these subsidiaries. We and our subsidiaries may incur additional debt. The indenture governing the notes does not contain any restriction on us or our subsidiaries incurring additional debt.

An active trading market for the notes may not develop.

There is no existing trading market for the notes. We do not plan to apply for listing of any notes sold pursuant to this prospectus on any securities exchange or for inclusion of such notes in any automated quotation system. If the notes are traded after their initial issuance, they may trade at a discount, depending on the prevailing interest rates, the market for similar securities, the price of our common stock, our

Table of Contents

performance and other factors. We do not know whether an active trading market will develop for the notes. To the extent that an active trading market does not develop, the price at which you may be able to sell the notes, if at all, may be less than the price you pay for them.

Certain provisions of law, as well as provisions in our bylaws and shareholder rights plan, may make it more difficult for others to obtain control of us, even though some shareholders might consider this favorable.

We are a Minnesota corporation and certain anti-takeover provisions of Minnesota law apply to us and create various impediments to the acquisition of control of us or to the consummation of certain business combinations with us. In addition, our bylaws and shareholder rights plan contain provisions which may make it more difficult to remove incumbent directors or effect certain business combinations with us without the approval of our board of directors. See Description of Capital Stock. Finally, certain federal and state utility regulatory statutes may also make it difficult for another party to acquire a controlling interest in us. These provisions of law and of our corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

We may enter into acquisitions, changes of control, refinancings or other recapitalizations or highly leveraged transactions that could increase the amount of debt outstanding, affect our capital structure or credit quality, or otherwise adversely affect the notes.

We may decide to enter into acquisitions, changes of control, refinancings of our current debt or other recapitalizations or highly leveraged transactions that could increase the amount of debt outstanding, affect our capital structure or credit quality, or otherwise adversely affect investors such as holders of the notes. Holders of the notes covered by this prospectus are not protected in the event of a highly leveraged transaction or a change of control except that a change of control permits the repurchase of notes at the option of the holder.

We may issue additional shares of our common stock that could dilute the value of our common stock issuable upon conversion of the notes.

We may be required to issue additional shares of our common stock that may dilute the value of our common stock and may adversely affect the market price our common stock.

On March 13, 2001, NRG completed the sale of 11.5 million equity units, consisting 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. Initially the equity units were convertible by the holder into NRG common stock. Following the exchange offer and subsequent short form merger pursuant to which we acquired the outstanding publicly-held stock of NRG on June 3, 2002, the equity units may be converted by the holder into our common stock. The maximum number of shares to be issued by us upon conversion of the equity units is 5,323,925 (subject to adjustment for specified events arising from stock splits and combinations, stock dividends and other actions that modify our capital structure).

We and some of our subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. As of December 31**,** 2002, stock options for 16,981,207 shares of common stock were outstanding, of which options for 8,992,632 shares of common stock were exercisable. The exercise price for the options ranges from $11.50 to $63.60. In addition, certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally ratably over a three year period. We granted 50,083 restricted shares in 2002, 21,774 restricted shares in 2001, 58,690 restricted shares in 2000 and 52,688 restricted shares in 1999.

Our ability to pay dividends on our common stock may be restricted by regulatory requirements.

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

Table of Contents

Xcel Energy were a deficit of $101 million at December 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 September 30, 2003. It is not known when or if the SEC will act on this request. See Note 12 to the consolidated financial statements for a discussion of factors affecting our payment of dividends.

Fluctuations in the market price of our common stock could adversely affect the trading price of the notes.

The market price of our common stock has fluctuated recently. In addition, the stock market in recent years has experienced significant price and volume fluctuations that have often been unrelated to the operating performance of companies. The market price of our common stock may continue to fluctuate in the future. Negative fluctuations in the market price of our common stock could adversely impact the trading price of the notes.

RATIO OF EARNINGS TO FIXED CHARGES

	Year ended December 31,				
	2002(1)	**2001**	**2000**	**1999**	**1998**
Ratio of Earnings to Fixed Charges(2)	(1.8)	2.1	1.9	2.4	3.0

(1) Earnings as defined in the ratio for the twelve months ended December 31, 2002 were reduced by NRG asset impairment charges of $3.1 billion. The fixed charges exceeded earnings, as defined for this ratio, by $2.9 billion in 2002.

(2) For purposes of computing the ratio of earnings to fixed charges:

earnings consist of net income 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

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.

USE OF PROCEEDS

We will not receive any proceeds from the sale by any selling security holder of the notes or the common stock issuable upon conversion of the notes. See Selling Security Holders.

Table of Contents

PRICE RANGE OF COMMON STOCK AND DIVIDEND HISTORY

Our common stock is currently listed on the New York Stock Exchange under the symbol XEL. The following table sets forth the intra-day high and low prices for transactions involving our common stock for each calendar quarter, as reported on the New York Stock Exchange Composite Tape, and related dividends paid per common share during such periods.

	High	Low	Dividend
2003:			
First Quarter	$ 12.97	$ 10.59	N/A
2002:			
Fourth Quarter	$ 11.60	$ 7.40	$ 0.1875
Third Quarter	$ 17.20	$ 5.12	$ 0.1875
Second Quarter	$ 26.49	$ 13.91	$ 0.3750
First Quarter	$ 28.49	$ 22.26	$ 0.3750
2001:			
Fourth Quarter	$ 29.77	$ 25.30	$ 0.3750
Third Quarter	$ 29.51	$ 25.00	$ 0.3750
Second Quarter	$ 31.85	$ 27.39	$ 0.3750
First Quarter	$ 30.35	$ 24.19	$ 0.3750
2000:			
Fourth Quarter	$ 30.00	$ 24.63	$ 0.3750
Third Quarter	$ 27.56	$ 20.13	$ 0.3750
Second Quarter	$ 23.81	$ 19.50	$ 0.3675
First Quarter	$ 20.56	$ 16.13	$ 0.3625

On May 9, 2003 the last reported sale price of our common stock on the New York Stock Exchange was $13.81 per share. As of December 31, 2002, there were approximately 128,000 holders of our common stock.

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 such decision, 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. 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. Retained earnings were $115 million at December 31, 2002 based on preliminary results. We requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until September 30, 2003.

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 the (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 December 31, 2002 was 85 percent. Although, we have preferred stock outstanding, 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.

Historical stock price information for periods prior to August 19, 2000 is information for the common stock of Northern States Power Company (which was listed on the New York Stock Exchange under the symbol NSP), the predecessor of Xcel Energy. Xcel Energy was formed on August 18, 2000 by the merger of Northern States Power Company with New Century Energies, Inc.

Table of Contents

CAPITALIZATION

The following table sets forth our consolidated capitalization as of December 31, 2002. We will not receive any proceeds from the sale by any selling security holders of the notes or the common stock issuable upon conversion of the 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 December 31, 2002(1)	
	(Thousands of Dollars)	% of Capitalization
Short-term debt, including current maturities	$ 9,298,224	43.97%
Minority interest	34,762	0.16%
Long-term debt	6,550,248	30.97%
Mandatorily redeemable preferred securities of subsidiary trusts	494,000	2.34%
Preferred stockholders equity	105,320	0.5%
Common stockholders equity	4,664,984	22.06%
Total capitalization (including short-term debt and minority interest)	$ 21,147,538	100.0%

(1) Actual capitalization amounts are as reported in our Consolidated Statements of Capitalization, which include amounts reclassified to discontinued operations of NRG. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $445.7 million of short-term debt is reported as current liabilities held for sale and $0.1 million of long-term debt is noncurrent liabilities held for sale.

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 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 other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Year Ended December 31,				
	2002(1)	2001	2000	1999	1998
	(In millions, except per share data)				
Consolidated Statement of Operations Data:					
Operating revenue(2)	$ 9,524	$ 11,333	$ 9,223	$ 6,883	$ 6,606
Operating expense(2)	10,957	9,475	7,744	5,679	5,412
Operating income (loss)	$ (1,433)	$ 1,858	$ 1,479	$ 1,204	$ 1,194
Interest income and other nonoperating income net of other expenses	44	46	16	3	49
Interest charges and financing costs	918	766	653	453	383
Income taxes (benefits)	(628)	331	299	180	240
Minority interest (income) expense	(17)	68	30	3	
(Loss) income from continuing operations	$ (1,661)	738	514	571	620
(Loss) income from discontinued operations, net of tax	(557)	47	32		4
Extraordinary items, net of tax		10	(19)		
Net (loss) income	(2,218)	795	527	571	624
Dividends on preferred stock	4	4	4	5	5
(Loss) earnings available for common shareholders	$ (2,222)	$ 791	$ 523	$ 566	$ 619
Earnings per share diluted:					
(Loss) income before extraordinary items	(4.36)	2.13	1.51	1.70	1.91
Discontinued Operations	(1.46)	0.14	0.09		
Extraordinary items		0.03	(0.06)		
Total	$ (5.82)	$ 2.30	$ 1.54	$ 1.70	$ 1.91

(1) Results for 2002 include two significant items that 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 to 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.

	December 31,	
	2002	2001
	(In millions)	
Consolidated Balance Sheet Data:		
Current assets	$ 3,737	$ 3,330
Net Property, plant and equipment, at cost	18,816	19,781
Other assets	4,705	5,642
Total assets	$ 27,258	$ 28,754
Current portion of long-term debt(1)	7,756	393
Short-term debt	1,542	2,225
Other current liabilities	3,051	2,851
Total current liabilities	12,349	55,469
Deferred credits and other liabilities	3,060	4,321
Minority interest	35	615
Long-term debt(1)	6,550	11,556
Mandatorily redeemable preferred securities of subsidiary trusts	494	494
Preferred stockholders equity	105	105
Common stockholders equity	4,665	6,195
Total liabilities and equity	$ 27,258	$ 28,754

(1) Based on the defaults under certain NRG debt agreements, and NRG s lenders 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.

Table of Contents

SELECTED PRO FORMA CONSOLIDATED FINANCIAL DATA

The following selected pro forma consolidated financial data as of and for the year ended December 31, 2002 have been derived from our audited 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, our pro-forma financial information and related notes, and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Year Ended December 31, 2002(1)
	(In millions, except per share data)
Consolidated Statement of Operations Data:	
Operating revenue	$ 7,243
Operating expense	6,087
Operating income (loss)	$ 1,156
Interest income and other nonoperating income net of other expenses	40
Equity in losses of NRG	(3,464)
Interest charges and financing costs	424
Income taxes (benefits)	(462)
Minority interest (income) expense	(12)
Net loss	(2,218)
Dividends on preferred stock	4
Loss available for common shareholders	$ (2,222)
Earnings per share diluted	$ 5.82

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.5 billion), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

Table of Contents

	December 31, 2002(2)
	(In millions)
Consolidated Balance Sheet Data:	
Current assets	$ 2,286
Net Property, plant and equipment, at cost	11,973
Other assets	2,089
Total assets	$ 16,348
Current portion of long-term debt	563
Short-term debt	512
NRG losses in excess of investment	634
Other current liabilities	1,513
Total current liabilities	3,222
Deferred credits and other liabilities	2,499
Minority interest	5
Long-term debt	5,358
Mandatorily redeemable preferred securities of subsidiary trusts	494
Preferred stockholders equity	105
Common stockholders equity	4,665
Total liabilities and equity	$ 16,348

(2) 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.

28

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with Summary Consolidated Financial Data, Selected 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 Information 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 Information Regarding Forward Looking Statements and Risk Factors in this prospectus.

On August 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. (Xcel Energy). Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act 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 Co. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. As a stock-for-stock exchange for shareholders of both companies, the merger was accounted for as a pooling-of-interests and, accordingly, amounts reported for periods prior to the merger have been restated for comparability with post-merger results.

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

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. NRG is facing extreme financial difficulties. There is substantial doubt as to NRG s ability to continue as a going concern absent a restructuring through bankruptcy, and NRG will likely be the subject of a bankruptcy proceeding. See Notes 2, 3, 4 and 7 to the consolidated financial statements filed with this prospectus.

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

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on 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 consolidated financial statements and notes included in this prospectus. All note references refer to the notes to the consolidated financial statements.

Table of Contents

Results of Operations

Our earnings per share for the past three years were as follows:

	Contribution to Earnings per Share		
	2002	2001	2000
Continuing Operations Before Extraordinary Items:			
Regulated utility	$ 1.59	$ 1.90	$ 1.20
NRG (including impairments and restructuring charges)	(7.58)	0.44	0.37
Other nonregulated 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:

	Contribution to Earnings per Share		
	2002	2001	2000
Regulated utility (including extraordinary items):			
Electric utility	$ 1.33	$ 1.66	$ 1.03
Gas utility	0.26	0.24	0.17
Total regulated utility	1.59	1.90	1.20
NRG (including discontinued operations) (see Note 3)	(9.04)	0.58	0.46
Other nonregulated 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 2002 Results

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

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

During 2002, NRG experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events led to impairment reviews of a number of NRG assets, which resulted in material write-downs in 2002. In addition to impairments of projects operating or under development, certain NRG projects were determined to be held for sale, and estimated losses on disposal for such projects were also recorded. These impairment charges, some of which related to equity investments, have reduced 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 will likely be the subject of a bankruptcy proceeding.

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

Tax Benefit NRG Investment As discussed in Note 11, 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 International recorded impairment losses for Argentina assets of 3 cents per share and disposal losses for Yorkshire Power of 2 cents per share, Planergy recorded gains from contract sales of 2 cents per share, losses were incurred on holding company debt of 2 cents per share, and incremental costs related to NRG financial restructuring activities of 1 cent per share were incurred at the holding company level.

Significant Factors that Impacted 2001 Results

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

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

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

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

Table of Contents

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

Significant Factors that Impacted 2000 Results

*Special Charges Merger Costs*During 2000, 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 8 cents per share were associated with merger impacts on nonregulated and holding company activities other than NRG. See Note 2 to the consolidated financial statements for more information on these merger-related costs reported as Special Charges.

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

Statement of Operations

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

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.

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 our other operating utilities, pursuant to a joint operating agreement (JOA) approved by the Federal Energy Regulatory Commission (FERC). Trading margins reflect the impact of sharing certain trading margins under the ICA. Trading revenues, as discussed in Note 1 to the consolidated financial statements, are reported net (i.e., margins) in the consolidated statements of operations. Trading revenue and costs associated with NRG s operations are included in nonregulated margins. The following table details the revenue and margin for base electric utility, short-term wholesale and electric and natural gas trading activities.

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

2002 Comparison to 2001 Base electric utility revenue decreased $375 million, 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 lower power prices and less favorable market conditions. The decrease in natural gas commodity trading margin reflects reduced market opportunities.

33

Table of Contents

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

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

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.

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

Table of Contents

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

2001 Comparison to 2000 Nonregulated revenue and margin from continuing operations increased in 2001, largely due to NRG s acquisition of generating facilities, increased demand for electricity, market dynamics, strong performance from existing assets and higher market prices for electricity. Earnings from equity investments for 2001 increased compared with 2000, primarily due to increased equity earnings from NRG projects, which offset lower equity earnings from Yorkshire Power. As a result of a sales agreement to sell most of 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 Other utility operating and maintenance expense for 2002 decreased by approximately $4 million, or 0.3 percent. The decreased costs reflect lower incentive compensation and other employee benefit costs, as well as lower staffing levels in corporate areas. These decreases were substantially offset by higher plant outage and property insurance costs, in addition to inflationary factors such as market wage increases.

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

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

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

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

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

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

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

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

Table of Contents

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 2002 increased earnings by an estimated 6 cents per share;

weather in 2001 had minimal impact on earnings per share; and

weather in 2000 increased earnings by an estimated 1 cent per share.

NRG Results

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

NRG Continuing Operations and Tax Credits As previously stated, NRG is facing extreme financial difficulties, and there is substantial doubt as to NRG s ability to continue as a going concern. During 2002, NRG s continuing operations, excluding impacts of asset impairments and disposals and restructuring costs, experienced significant losses compared with 2001. The 2002 losses are primarily attributable to NRG s North American operations, which experienced significant reductions in domestic energy and capacity sales and an overall decrease in power pool prices and related spark spreads. During 2002, an additional reserve for uncollectible receivables in California was established by West Coast Power, which reduced NRG s equity earnings by approximately $29 million, after tax. West Coast Power s 2002 income 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

Table of Contents

strategies and a higher percentage of NRG s overall earnings derived from foreign projects in lower tax jurisdictions.

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

Other Nonregulated Subsidiaries and Holding Company Results

	Contribution to Xcel Energy s Earnings per Share		
	2002	**2001**	**2000**
Xcel International	$ (0.05)	$ (0.02)	$ 0.09
Eloigne Company	0.02	0.03	0.02
Seren Innovations	(0.07)	(0.08)	(0.07)
Planergy International	0.00	(0.04)	(0.08)
e prime	0.00	0.02	(0.02)
Financing costs and preferred dividends	(0.11)	(0.11)	(0.07)
Other nonregulated/ holding company results	(0.01)	0.02	0.01
Subtotal nonregulated/ holding co. excluding tax benefit	(0.22)	(0.18)	(0.12)
Tax benefit from investment in NRG (Note 11)	1.85		
Total nonregulated/ holding company earnings per share	$ 1.63	$ (0.18)	$ (0.12)

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

In December 2002, a subsidiary of Xcel Argentina decided it would no longer fund one of its power projects in Argentina and defaulted on its loan agreements. The default is not material to 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 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 consolidated financial statements.

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

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

Table of Contents

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

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

e prime e prime s results for the year ended 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 results include interest expense and preferred dividends, which are incurred at the our and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

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

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

Factors Affecting Results of Operations

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. The historical and future trends of our operating results have been, and are expected to be, affected by the following factors:

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

Table of Contents

plan. See further discussion of potential NRG bankruptcy and financial restructuring under Liquidity and Capital Resources and in Notes 4 and 18 to the consolidated financial statements.

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

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

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

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

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 1.8 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 approximately the same in 2002 compared with 2001, and 2.6 percent in 2001 compared with 2000. We are projecting that 2003 weather-normalized sales growth in 2003 compared with 2002 will be 1.5 to 2.0 percent for retail electric utility customers and 2.5 to 3.0 percent for firm gas utility customers.

Table of Contents

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, 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.

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

Critical Accounting Policies Preparation of consolidated financial statements and related disclosures in compliance with generally accepted accounting principles (GAAP) requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the consolidated financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the consolidated financial statements and related disclosures, even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most significant to the portrayal of 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 Consolidated Financial Statements Notes 2, 3 and 18

Table of Contents

Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
NRG Financial Restructuring	Terms negotiated to settle NRG s obligations to its creditors Ownership interest in and control of NRG, and related ability to continue consolidating NRG as a subsidiary Impacts of court decisions in future bankruptcy proceedings, including any obligations of Xcel Energy	Management s Discussion and Analysis: Liquidity and Capital Resources NRG Financial Issues Xcel Energy Impacts Notes to Consolidated Financial Statements Notes 4 and 18
Income Tax Accruals	Application of tax statutes and regulations to transactions Anticipated future decisions of tax authorities Ability of tax authority decisions/ positions to withstand legal challenges and appeals Ability to realize tax benefits through carrybacks to prior periods or carryovers to future periods	Management s Discussion and Analysis: Factors Affecting Results of Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 11 and 18
Benefit Plan Accounting	Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition Interest rates used in valuing benefit obligation Actuarial period selected to recognize deferred investment gains and losses	Management s Discussion and Analysis: Factors Affecting Results of Operations Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements Notes 1 and 13
Regulatory Mechanisms and Cost Recovery	External regulator decisions, requirements and regulatory environment Anticipated future regulatory decisions and their impact Impact of deregulation and competition on ratemaking process and ability to recover costs	Management s Discussion and Analysis: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to Consolidated Financial Statements Notes 1, 18 and 20

Table of Contents

Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
Environmental Issues	Approved methods for cleanup Responsible party determination Governmental regulations and standards Results of ongoing research and development regarding environmental impacts	Management s Discussion and Analysis: Factors Affecting Results of Operations Environmental Matters Notes to Consolidated Financial Statements Notes 1 and 18
Uncollectible Receivables	Economic conditions affecting customers, suppliers and market prices Regulatory environment and impact of cost recovery constraints on customer financial condition Outcome of litigation and regulatory proceedings	Management s Discussion and Analysis: Factors Affecting Results of Operations California Power Market Notes to Consolidated Financial Statements Notes 1 and 18
Nuclear Plant Decommissioning and Cost Recovery	Costs of future decommissioning Availability of facilities for waste disposal Approved methods for waste disposal Useful lives of nuclear power plants Future recovery of plant investment and decommissioning costs	Notes to Consolidated Financial Statements Notes 1, 18 and 19

Pension Plan Costs and Assumptions 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 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 in 2003 expect to change the 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

Table of Contents

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 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 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 Service (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

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

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

The electric and natural gas rates charged to customers of 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 are not recovered through these rate adjustment mechanisms. For Wisconsin electric operations, where automatic cost-of-energy adjustment clauses are not allowed, the biennial retail rate review process and an interim fuel-cost hearing process provide the opportunity for rate recovery of changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In Colorado, PSCo has an ICA mechanism that allows for an equal sharing among customers and shareholders of certain fuel and energy costs and certain gains and losses on trading margins.

Regulated public utilities are allowed to record as regulatory assets certain costs that are expected to be recovered from customers in future periods and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, nonregulated enterprises would expense these costs and recognize the income in the current period. If restructuring or other changes in the regulatory environment occur, 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 December 31, 2002, we reported on our balance sheet regulatory assets of approximately $404 million and regulatory liabilities of approximately $297 million that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. 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 consolidated financial statements for further discussion of regulatory deferrals.

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;

Table of Contents

- 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
  - an annual electric earnings test with the sharing of earnings in excess of the return on equity set in the 2002 rate case for 2004 through 2006
- an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2006;

a 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; and an ICA that provides for the sharing of energy costs and savings relative to an annual baseline cost per kilowatt-hour generated or purchased. According to the terms of the merger rate agreement in Colorado, the annual baseline cost will be reset in 2002, based on a 2001 test year. Pursuant to a stipulation approved by the CPUC, the ICA remains in effect through March 31, 2005, to recover allowed ICA costs from 2001 and 2002. The recovery of fuel and purchased energy expense beginning Jan. 1, 2003, will be decided in the PSCo 2002 general rate case. In the interim period until the conclusion of the general rate case, 2003 fuel and purchased energy expense is recovered through the interim adjustment clause (IAC).

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

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

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

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

The total disallowance of interest expense deductions for the period 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:

$149 million in 2002

$146 million in 2001

$144 million in 2000

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

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

$108 million in 2002

$136 million in 2001

$57 million in 2000

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

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

Impact of Other Nonregulated Investments 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 natural gas marketing and trading through e prime and 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

Table of Contents

strategic fit in our business portfolio. As of December 31, 2002, our investment in Seren was approximately $255 million. Seren had capitalized $290 million for plant in service and had incurred another $21 million for construction work in progress for these systems at December 31, 2002. Xcel Energy International s gross investment in Argentina, excluding unrealized currency translation losses of approximately $62 million, was $112 million at December 31, 2002. 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 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.

Pending Accounting Changes

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 Accounting for Asset Retirement Obligations. This statement will require us to record our 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.

We currently follow industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in accumulated depreciation. At December 31, 2002, we 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.

We adopted SFAS No. 143 as required on January 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.

We have 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 we intend to utilize these properties indefinitely. The

Table of Contents

asset retirement obligations for the ash ponds and generating plants cannot be reasonably estimated due to an indeterminate life for the assets associated with the ponds and uncertain retirement dates for the generating plants. Since the time period for retirement is unknown, no liability would be recorded. When a retirement date is certain, a liability will be recorded.

SFAS No. 143 will also affect our accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a GAAP liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates over time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, we have an estimated regulatory liability accrued in accumulated depreciation for future removal costs of the following amounts at December 31, 2002:

	(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 supercedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things. Adoption of SFAS No. 145 may affect the recognition of impacts from NRG s financial improvement and restructuring plan, if existing debt agreements are ultimately renegotiated while NRG is still a consolidated subsidiary of us. Other impacts of SFAS No. 145 are not expected to be material to us.

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

SFAS No. 148 In December 2002, the FASB issued SFAS No. 148 Accounting for Stock-Based Compensation Transition and Disclosure, amending FASB Statement No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation, and requiring disclosure in both annual and interim consolidated financial statements about the method used and the effect of the method used on results. 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 does not plan at this time to adopt the voluntary provisions of SFAS No. 148.

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

FASB Interpretation No. 45 (FIN No. 45) In November 2002, the FASB issued FIN No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others . The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after 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.

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, we expect that we will have to consolidate our affordable housing investments made through Eloigne, which currently are accounted for under the equity method.

As of December 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 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. Had we adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. We plan to adopt FIN No. 46 when required in the third quarter of 2003.

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

Currency Exchange Risk We and our subsidiaries have certain investments in foreign countries, creating exposure to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. 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 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 the company s 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.

Trading 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. 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. Our risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by the company s risk management committee, which is made up of management personnel not involved in the trading operations.

The fair value of our trading contracts as of December 31, 2002, is as follows:

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

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

Table of Contents

The future maturities of our trading contracts are 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

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

As of 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, 2002	During 2002 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.

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.

Table of Contents

Liquidity and Capital Resources

Cash Flows

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

Cash provided by operating activities increased during 2002, compared with 2001, primarily due to NRG s efforts to conserve cash by deferring the payment of interest payments and managing its cash flows more closely. NRG s accrued interest costs rose by nearly $200 million in 2002 compared 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.

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

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

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

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

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

Capital Requirements

Utility Capital Expenditures, Nonregulated Investments and Long-term Debt Obligations The estimated cost of 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.

Table of Contents

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

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 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 the PUHCA restrictions. At December 31, 2002, such investments exceeded consolidated retained earnings.

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

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

Contractual Obligations and Other Commitments We have a variety of contractual obligations and other commercial commitments that represent prospective requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in the Consolidated Statements of Capitalization and Notes 5, 6, 7, 16 and 18 to the consolidated financial statements.

Table of Contents

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

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

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

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 December 31, 2002, was 85 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

Capital Sources

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 the PUHCA, we are required to maintain a common equity ratio of 30 percent or higher in its consolidated capital structure.

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

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

In December 2002, we filed a request for additional financing authorization with the SEC. We requested an increase from $2.0 billion to $2.5 billion in the aggregate amount of securities that we may issue during the period through September 30, 2003. In addition, the request proposed that common equity will be at least 30 percent of total consolidated capitalization, provided that in any event that the 30-percent common equity requirement is not met, we may issue common stock. The notice period expired with no comments. SEC action on the request is pending. As a result, we at the present time cannot finance, either on a short-term or long-term basis, without SEC approval unless our common equity is at least 30 percent of total capitalization.

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

Short-Term Funding Sources Historically, 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 Statement of Operations Analysis and Factors Affecting Results of Operations.

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. These factors are evaluated by credit rating agencies that review 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, 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 consolidated financial statements.

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

Table of Contents

to revision or withdrawal at any time by the rating company. As of April 14, 2003, the following represents the credit ratings assigned to various Xcel Energy companies:

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

* Negative credit watch/negative outlook

** Below investment grade

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 consolidated financial statements. In addition, lower credit ratings will 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.

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 credit ratings in previous table. NRG anticipates funding its ongoing capital requirements through committed debt facilities, operating cash flows, and existing cash.

NRG s operating cash flows have been affected by lower operating margins as a result of low power prices since mid-2001. Seasonal variations in demand and market volatility in prices are not unusual in the independent power sector, and NRG does normally experience higher margins in peak summer periods and

Table of Contents

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 of December 31, 2002, Loy Yang, Energy Center Kladno, LSP Energy (Batesville), NRG South Central, and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG. In addition, NRG s subsidiaries, including LSP Kendall, NRG McClain, NRG Mid-Atlantic, NRG South Central and NRG Northeast Generating are in default on their various debt instruments, resulting in dividend payment restrictions.

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

Registration Statements Our Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of December 31, 2002, 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 December 31, 2002, we had approximately 1 million shares of preferred stock outstanding. Registered securities available for issuance are as follows:

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, which we can only issue when our common equity exceeds 30 percent of our total capitalization absent SEC approval under PUHCA.

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

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

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

In April 14, 2003, PSCo filed a registration statement on Form S-3 with the SEC, registering $500 million of new secured first collateral trust bonds or unsecured senior debt securities. The registration statement also constitutes a post-effective amendment to PSCo s registration statement on Form S-3 filed with the SEC in June 1999 under which $300 million of unsecured senior debt securities remain unsold.

Other Liquidity and Capital Resource Considerations

NRG Financial Issues and Potential Bankruptcy Historically, NRG has obtained cash from operations, issuance of debt and equity securities, borrowings under credit facilities, capital contributions from us,

Table of Contents

reimbursement by us of tax benefits pursuant to a tax-sharing agreement and proceeds from non-recourse project financings. NRG has used these funds to finance operations, service debt obligations, fund the acquisition, development and construction of generation facilities, finance capital expenditures and meet other cash and liquidity needs.

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

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

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

As previously discussed, 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. NRG s management has concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations.

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

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

Table of Contents

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

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

At the present time and based on conversations with various lenders, our management believes that the appropriate course is to seek a consensual restructuring of NRG with its creditors. Following an agreement on the restructuring with NRG s creditors, as described in Note 4 to the consolidated financial statements, it is expected that NRG would commence a Chapter 11 bankruptcy proceeding and immediately seek approval of a prenegotiated plan of reorganization. If a consensual restructuring cannot be reached, the likelihood of NRG becoming subject to a protracted voluntary or involuntary bankruptcy proceeding is increased. If a consensual restructuring of NRG cannot be obtained and NRG remains outside of a bankruptcy proceeding, NRG is expected to continue selling assets to reduce its debt and improve its liquidity. Through 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.

Xcel Energy Impacts During 2002, we provided NRG with $500 million of cash infusions. In May 2002, we and NRG entered into a support and capital subscription agreement (Support Agreement) pursuant to which we agreed, under certain circumstances, to provide an additional $300 million to NRG.

We have not, to date, provided funds to NRG under this agreement. See discussion of preliminary settlement with NRG s creditors below and at Note 4 to the financial statements.

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

On March 26, 2003, 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. The settlement is subject to a variety of conditions as set forth below, including definitive documentation. As described in Note 4 to the consolidated financial statements, the settlement would require us to pay up to $752 million over 13 months. We would expect to fund those payments with cash from tax savings. The principal terms of the settlement as of the date of this report were as follows:

We would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, 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 January 1, 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 on April 30, 2004, except to the extent that we had not received at such time tax refunds equal to $352 million associated with the loss on our investment in NRG. To the extent we had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of our payments are contingent on receiving releases from NRG creditors. To the extent we do not receive a release from 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 releases from at least 85 percent of the claims in various NRG creditor groups. 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 the our payment due on April 30, 2004.

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

As part of the settlement with us, any intercompany claims of us 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 January 31, 2003 will be reduced from approximately $55 million as asserted by us 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 us or any of our 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 us. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss we expect to incur in connection with the write down of our investment in NRG.

Our obligations under the tentative settlement, including our 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 us, 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 September 30, 2003;

(4) The receipt of releases in our favor by at least 85 percent of the claims represented by the NRG Credit Facilities;

(5) The receipt by us of all necessary regulatory approvals; and

(6) No downgrade prior to consummation of the settlement of any of our 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 our investment in NRG, we would recognize the expected tax benefits of the write-off as of December 31, 2002. The tax benefit has been estimated at approximately $706 million. This benefit is based on the tax basis of our investment in NRG.

We expect to claim a worthless stock deduction in 2003 on our investment. This would result in us 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. We expect to file for a tax refund of approximately $355 million in first quarter 2004. This is refund 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, we expect 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 our taxable income.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities; to 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, 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 or related theories, should an NRG bankruptcy proceeding commence, particularly in the absence of a prenegotiated plan of reorganization, and we cannot be certain how a bankruptcy court would resolve these issues. One of the creditors of the NRG project Pike, as discussed in Note 18 to the consolidated financial statements, has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and us. Also, as discussed in Note 18 to the consolidated financial statements, a group of former executives of NRG have commenced an involuntary bankruptcy proceeding against NRG related to the payments of certain benefits and deferred compensation amounts claimed to be due them. If a bankruptcy court were to allow substantive consolidation of us and NRG, it would have a material adverse effect on us.

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 us to fully relinquish our effective control over NRG, we anticipate that NRG would no longer be included in our consolidated financial statements, prospectively from the date such actions were taken. Such de-consolidation of NRG would encompass a change in our accounting for NRG to the equity method, under which we would continue to record our interest in NRG s income or losses until our investment in NRG (under the equity method) reached the level of obligations that we 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 December 31, 2002, our 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 us exceeded that level after de-consolidation of NRG, then NRG s losses would continue to be included in our results until the amount of negative investment in NRG reaches the amount of guarantees and financial assistance committed to by us. As of December 31, 2002, the estimated guarantee exposure that we had provided on behalf of NRG of $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 we 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 we, 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, our 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 our 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 December 31, 2002. Additional tax benefits could be recorded in 2003 at the time that such benefits are considered likely of realization, when the payment of guarantees and other financial assistance to NRG become probable.

As noted above, a bankruptcy filing by NRG would have several effects on our financial condition and results of operations. If a bankruptcy filing and other necessary governance actions eliminate our control over

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

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, nor are we contingently liable to creditors of NRG in an amount material to our liquidity. 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, 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, 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.

Table of Contents

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 six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, Cheyenne and BMG. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Our regulated businesses also include Viking, which we sold on January 17, 2003, and WGI, both interstate natural gas pipeline companies.

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 shares of Xcel Energy 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, NRG is currently experiencing severe financial difficulties and has sold or is in the process of selling a significant amount of its assets.

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 inc., which is involved in natural gas marketing and trading;
- Planergy, which is involved in enterprise energy management solutions;
- Eloigne, which is involved in investments in 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 executive offices are located at 800 Nicollet Mall, Minneapolis, Minnesota 55402.

For information on our nonregulated subsidiaries, see Nonregulated Subsidiaries below. For information regarding our segments and foreign revenues, see Note 21 to the 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.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; NSP Nuclear Corp., which holds NSP-Minnesota s interest in the Nuclear Management Co.; and NSP Financing I, a special purpose business trust.

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; Green and Clear Lakes Company, which owns water rights and PSCo Capital Trust I, a special purpose financing trust. PSCo also holds controlling interests in several other relatively small ditch and water companies whose capital requirements are not significant. PS Colorado Credit Corp., a finance company that was owned by PSCo and financed certain of PSCo s current assets was dissolved in 2002.

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. The wholesale customers served by SPS comprise approximately 36 percent of the total kilowatt-hour sales.

SPS owns a direct subsidiary, SPS Capital I, which is 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 9,300 customers. We have entered into an agreement to sell BMG. The sale is subject to the receipt of several regulatory approvals.

Viking, acquired in 1993, owns and operates an interstate natural gas pipeline serving portions of Minnesota, Wisconsin and North Dakota. Viking operates exclusively as a transporter of natural gas for third-party shippers under authority granted by the FERC. On January 17, 2003, we completed the sale of Viking, including its ownership interest in Guardian, to a subsidiary of NBP.

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.

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.

FERC has jurisdiction over rates for electric transmission service in interstate commerce and wholesale 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. 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.

Table of Contents

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

Viking and WGI are subject to the FERC jurisdiction and each holds a FERC certificate, which allows them to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act. BMG is subject to the regulation of the Arizona Corporation Commission (ACC).

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.

Table of Contents

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 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 had or currently has seven adjustment clauses that recover fuel, purchased energy and resource costs: the ICA, the interim adjustment clause (IAC), the air quality improvement rider (AQIR), the gas cost adjustment (GCA), the steam cost adjustment (SCA), the demand side management cost adjustment (DSMCA) and the qualifying facilities capacity cost adjustment (QFCCA). These adjustment clauses allow certain costs to be passed through to 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 allowed for an equal sharing between customers and shareholders of certain fuel and purchased energy cost increases for fuel and purchased energy costs incurred prior to December 31, 2002. The IAC recovers fuel and energy costs incurred during 2003 until the conclusion of the 2002 general rate case, at which time the fuel and purchased energy cost recovery from January 1, 2003 onward shall be recalculated in accord with the fuel and purchased energy cost recovery mechanism approved by the Commission in the PSCo 2002 general rate case. The AQIR recovers over a fifteen year period the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of voluntary investments in air quality improvement. 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. The QFCCA provides for recovery of purchased capacity costs from certain QF projects not otherwise reflected in base electric rates. The QFCCA will expire at the conclusion of PSCo s general rate case will expire at the conclusion of the 2002 general rate case. 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.

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 an