



4/28/2022

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
FIRST QUARTER 2022 EARNINGS REPORT

- First quarter GAAP diluted earnings per share were \$0.70 in 2022 compared with \$0.67 in 2021.
- Xcel Energy reaffirms 2022 EPS earnings guidance range of \$3.10 to \$3.20.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2022 first quarter GAAP and ongoing earnings of \$380 million, or \$0.70 per share, compared with \$362 million, or \$0.67 per share in the same period in 2021.

Earnings reflect capital investment recovery and other regulatory outcomes, partially offset by higher depreciation, interest expense and operating and maintenance (O&M) expenses.

“Xcel Energy achieved solid first quarter results, and we have reaffirmed our 2022 earnings guidance,” said Bob Frenzel, chairman, president and CEO. “We reached constructive regulatory outcomes on several key matters, including approval of our Upper Midwest Resource Plan, the Colorado Power Pathway transmission project and an electric rate case in Colorado.

The Upper Midwest Resource Plan adds approximately 5,800 megawatts of wind and solar energy to our system, extends the life of our carbon-free Monticello nuclear plant to 2040 and retires our coal fleet in the region by 2030. The Colorado Power Pathway project is a \$1.7 billion investment that will enable approximately 5,500 MW of new renewables, including access to some of the richest wind resources in the region.”

At 9:00 a.m. CDT today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in 5 to 10 minutes prior to the start and follow the operator’s instructions.

US Dial-In: (800) 289-0720
International Dial-In: (400) 120-9264
Conference ID: 7267038

The conference call also will be simultaneously broadcast and archived on Xcel Energy’s website at www.xcelenergy.com. To access the presentation, click on Investors under Company. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CDT on April 28 through 12:00 p.m. CDT on May 1.

Replay Numbers

US Dial-In: (888) 203-1112
International Dial-In: (719) 457-0820
Access Code: 7267038

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to 2022 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should,” “will,” “would” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in Xcel Energy’s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 and subsequent filings with the Securities and Exchange Commission, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs, changes in regulation and subsidiaries’ ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers’ and counterparties’ ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries’ ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

For more information, contact:

Paul Johnson, Vice President - Treasurer & Investor Relations (612) 215-4535

For news media inquiries only, please call Xcel Energy Media Relations (612) 215-5300

Xcel Energy website address: www.xcelenergy.com

This information is not given in connection with any sale, offer for sale or offer to buy any security.

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions, except per share data)

	Three Months Ended March 31	
	2022	2021
Operating revenues		
Electric	\$ 2,633	\$ 2,870
Natural gas	1,090	647
Other	28	24
Total operating revenues	<u>3,751</u>	<u>3,541</u>
Operating expenses		
Electric fuel and purchased power	1,094	1,386
Cost of natural gas sold and transported	710	299
Cost of sales — other	10	8
Operating and maintenance expenses	602	584
Conservation and demand side management expenses	92	73
Depreciation and amortization	562	521
Taxes (other than income taxes)	171	163
Total operating expenses	<u>3,241</u>	<u>3,034</u>
Operating income	510	507
Other income, net	1	5
Earnings from equity method investments	15	14
Allowance for funds used during construction — equity	13	14
Interest charges and financing costs		
Interest charges — includes other financing costs of \$8 and \$7, respectively	214	205
Allowance for funds used during construction — debt	(5)	(5)
Total interest charges and financing costs	<u>209</u>	<u>200</u>
Income before income taxes	330	340
Income tax benefit	(50)	(22)
Net income	<u>\$ 380</u>	<u>\$ 362</u>
Weighted average common shares outstanding:		
Basic	545	538
Diluted	545	539
Earnings per average common share:		
Basic	\$ 0.70	\$ 0.67
Diluted	0.70	0.67

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Investor Relations Earnings Release (Unaudited)

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as certain non-GAAP financial measures such as ongoing return on equity (ROE), ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP. Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

Ongoing ROE is calculated by dividing the net income or loss of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results.

Earnings Adjusted for Certain Items (Ongoing Earnings and Ongoing Diluted EPS)

GAAP diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method. Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS for Xcel Energy is calculated by dividing net income or loss, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing diluted EPS for each subsidiary is calculated by dividing the net income or loss for such subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period.

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the three months ended March 31, 2022 and 2021, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Note 1. Earnings Per Share Summary

Xcel Energy's first quarter diluted earnings were \$0.70 per share in 2022, compared with \$0.67 per share in 2021. The increase was driven by regulatory recovery of capital investment, partially offset by higher depreciation, interest expense and O&M expenses. Costs for natural gas sold and transported significantly increased in 2022 primarily due to market price fluctuations. However, fluctuations in electric and natural gas revenues associated with changes in fuel and purchased power and/or natural gas sold and transported generally do not significantly impact earnings (changes in revenues are offset by the related variation in costs).

Summarized diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	Three Months Ended March 31	
	2022	2021
PSCo	\$ 0.32	\$ 0.31
NSP-Minnesota	0.23	0.24
SPS	0.10	0.11
NSP-Wisconsin	0.09	0.06
Earnings from equity method investments — WYCO	0.01	0.01
Regulated utility ^(a)	0.75	0.73
Xcel Energy Inc. and Other	(0.05)	(0.06)
Total ^(a)	\$ 0.70	\$ 0.67

^(a) Amounts may not add due to rounding.

PSCo — Earnings increased \$0.01 per share for the first quarter of 2022, reflecting regulatory recovery of capital investment and higher demand revenues, partially offset by increased depreciation, O&M expenses and incremental power costs from the Comanche Unit 3 outage (see Note 4).

NSP-Minnesota — Earnings decreased \$0.01 per share for the first quarter of 2022, as regulatory recovery of capital investment was offset by increased depreciation and O&M expenses.

SPS — Earnings decreased \$0.01 per share for the first quarter of 2022, primarily due to taxes (other than income taxes) and impacts associated with Winter Storm Uri, partially offset by favorable sales.

NSP-Wisconsin — Earnings increased \$0.03 per share for the first quarter of 2022, reflecting the impact of regulatory rate outcomes and higher sales attributable to weather, partially offset by higher O&M expenses.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company and earnings from Energy Impact Partners (EIP) funds equity method investments.

Components significantly contributing to changes in 2022 EPS compared to 2021:

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
GAAP and ongoing diluted EPS — 2021	\$ 0.67
Components of change - 2022 vs. 2021	
Higher electric revenues, net of electric fuel and purchased power	0.08
Lower effective tax rate (ETR) ^(a)	0.05
Higher natural gas revenues, net of cost of natural gas sold and transported	0.04
Higher depreciation and amortization	(0.06)
Higher O&M expenses	(0.02)
Higher taxes (other than income taxes)	(0.01)
Higher interest charges	(0.01)
Other, net	(0.04)
GAAP and ongoing diluted EPS — 2022	\$ 0.70

^(a) Includes production tax credits (PTCs) and plant regulatory amounts, which are primarily offset as a reduction to electric revenues.

Note 2. Regulated Utility Results

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy’s financial performance. However, decoupling mechanisms in Colorado and proposed sales true-up mechanisms in Minnesota predominately mitigate the positive and adverse impacts of weather for the electric utility.

Normal weather conditions are defined as either the 10, 20 or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Weather — Estimated impact of temperature variations on EPS compared with normal weather conditions:

	Three Months Ended March 31		
	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021
Retail electric	\$ 0.020	\$ —	\$ 0.020
Decoupling and sales true-up	(0.010)	0.002	(0.012)
Electric total	\$ 0.010	\$ 0.002	\$ 0.008
Firm natural gas	0.016	0.003	0.013
Total	\$ 0.026	\$ 0.005	\$ 0.021

Sales — Sales growth (decline) for actual and weather-normalized sales in 2022 compared to 2021:

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(1.4)%	4.7 %	0.3 %	6.2 %	1.9 %
Electric C&I	2.7	6.6	10.2	4.7	6.2
Total retail electric sales	1.2	5.9	8.0	5.2	4.8
Firm natural gas sales	(1.5)	20.6	N/A	22.1	6.7
Weather-Normalized					
Electric residential	(1.5)%	0.4 %	(0.1)%	0.8 %	(0.3)%
Electric C&I	2.7	5.9	10.1	4.1	5.9
Total retail electric sales	1.2	4.0	7.8	3.0	3.9
Firm natural gas sales	(1.2)	5.3	N/A	7.3	1.5

Weather-normalized electric sales growth (decline)

Weather-adjusted sales results for each of our utility subsidiaries in 2022 reflect generally improving economies as the adverse effects of COVID-19 lessen. The recovery reflects increased sales in the C&I sector due to increased economic activity. Individuals returning to work have led to declines in use per customer and overall residential sales.

- PSCo — Residential sales declined based on decreased use per customer, partially offset by a 1.2% increase in customers. The growth in C&I sales was due to a 1.3% increase in customers and higher use per customer, primarily the real estate and leasing, food services, energy and construction sectors.
- NSP-Minnesota — Residential sales growth reflects a 1.2% increase in customers, partially offset by decreased use per customer. The growth in C&I sales was primarily due to higher use per customer, particularly in the manufacturing, real estate and leasing, and food service sectors.
- SPS — Residential sales declined due to a lower use per customer, partially offset by a 1.0% increase in customers. C&I sales increased due to higher use per customer, primarily driven by the energy sector.
- NSP-Wisconsin — Residential sales growth was attributable to a 0.7% increase in customers. The growth in C&I sales was due to a 0.4% increase in customers and higher use per customer, primarily led by increases in the manufacturing, accommodation and food services and health care sectors.

Weather-normalized natural gas sales growth (decline)

- Natural gas sales reflect a higher customer use, primarily in NSP-Minnesota and NSP-Wisconsin, as well as a 1.2% increase in residential customers and a 0.5% increase in C&I customers.

Electric Margin — Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. See Note 4 for additional discussion.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these price fluctuations generally have minimal earnings impact due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes. Electric revenues, fuel and purchased power and margin:

(Millions of Dollars)	Three Months Ended March 31	
	2022	2021
Electric revenues	\$ 2,633	\$ 2,870
Electric fuel and purchased power	(1,094)	(1,386)
Electric margin	\$ 1,539	\$ 1,484

Change:

(Millions of Dollars)	Three Months Ended March 31, 2022 vs. 2021
Regulatory rate outcomes (Minnesota, Colorado, Wisconsin, Texas and New Mexico)	\$ 63
Non-fuel riders	36
Sales and demand ^(a)	22
Conservation and demand side management (offset in expense)	14
Estimated impact of weather (net of decoupling/sales true-up)	6
PTCs flowed back to customers (offset by lower ETR)	(53)
Proprietary commodity trading, net of sharing ^(b)	(25)
Comanche Unit 3 outage ^(c)	(9)
Other (net)	1
Total increase	\$ 55

^(a) Sales excludes weather impact, net of decoupling in Colorado and proposed sales true-up mechanism in Minnesota.

^(b) Includes \$27 million of net gains recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri.

^(c) See Note 4 for further information.

Natural Gas Margin — Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for the cost of natural gas sold are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas generally have minimal earnings impact due to cost recovery mechanisms. Natural gas revenues, cost of natural gas sold and transported and margin:

(Millions of Dollars)	Three Months Ended March 31	
	2022	2021
Natural gas revenues	\$ 1,090	\$ 647
Cost of natural gas sold and transported	(710)	(299)
Natural gas margin	\$ 380	\$ 348

Change:

(Millions of Dollars)	Three Months Ended March 31, 2022 vs. 2021
Regulatory rate outcomes (Minnesota, Wisconsin, North Dakota)	\$ 17
Estimated impact of weather	10
Gas sales and transport (excluding weather impact)	7
Other (net)	(2)
Total increase	\$ 32

O&M Expenses — O&M expenses increased \$18 million for the first quarter, due to additional investments in technology and customer programs, higher insurance premiums and additional bad debt expenses (primarily attributable to higher billings and/or increased commodity prices), partially offset by a reduction in employee benefit costs.

Depreciation and Amortization — Depreciation and amortization increased \$41 million for the first quarter. The increase was primarily driven by several wind farms going into service and normal system expansion.

Interest Charges — Interest charges increased \$9 million for the first quarter, largely due to increased long-term debt levels to fund capital investments and the unrecovered/deferred balances related to Winter Storm Uri.

Income Taxes — Effective income tax rate:

	Three Months Ended March 31		
	2022	2021	2022 vs 2021
Federal statutory rate	21.0 %	21.0 %	— %
State tax (net of federal tax effect)	4.9	4.9	—
(Decreases) increases:			
Wind PTCs ^(a)	(34.4)	(24.6)	(9.8)
Plant regulatory differences ^(b)	(4.8)	(6.1)	1.3
Other tax credits, net operating loss & tax credits allowances	(1.5)	(1.1)	(0.4)
Other (net)	(0.4)	(0.6)	0.2
Effective income tax rate	(15.2)%	(6.5)%	(8.7)%

^(a) Wind PTCs are credited to customers (reduction to revenue) and do not materially impact net income.

^(b) Plant regulatory differences primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit are offset by corresponding revenue reductions.

Income tax benefit increased \$28 million for the first quarter, primarily driven by an increase in wind PTCs.

In April 2022, the IRS published inflation factors used to determine the PTC rate. As a result, the 2022 PTC rate on the sale of electricity produced from wind is 2.7 cents per kilowatt hour, compared to 2.5 cents for 2021.

Note 3. Capital Structure, Liquidity, Financing and Credit Ratings

Xcel Energy's capital structure:

(Millions of Dollars)	March 31, 2022	Percentage of Total Capitalization	Dec. 31, 2021	Percentage of Total Capitalization
Current portion of long-term debt	\$ 851	2 %	\$ 601	1 %
Short-term debt	996	3	1,005	3
Long-term debt	21,534	55	21,779	56
Total debt	23,381	60	23,385	60
Common equity	15,732	40	15,612	40
Total capitalization	\$ 39,113	100 %	\$ 38,997	100 %

Liquidity — As of April 25, 2022, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility ^(a)	Drawn ^(b)	Available	Cash	Liquidity
Xcel Energy Inc.	\$ 1,250	\$ 641	\$ 609	\$ 1	\$ 610
PSCo	700	133	567	3	570
NSP-Minnesota	500	11	489	3	492
SPS	500	256	244	2	246
NSP-Wisconsin	150	50	100	1	101
Total	\$ 3,100	\$ 1,091	\$ 2,009	\$ 10	\$ 2,019

^(a) Expires June 2024.

^(b) Includes outstanding commercial paper and letters of credit.

Bilateral Credit Agreement — In April 2022, NSP-Minnesota extended an uncommitted bilateral credit agreement of \$75 million (limited in use to support letters of credit for one-year). NSP-Minnesota had \$45 million of outstanding letters of credit as of March 31, 2022.

Credit Ratings — Access to the capital markets at reasonable terms is partially dependent on credit ratings. The following ratings reflect the views of Moody's, S&P Global Ratings and Fitch. The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries as of April 25, 2022:

Credit Type	Company	Moody's	S&P Global Ratings	Fitch
Senior unsecured debt	Xcel Energy Inc.	Baa1	BBB+	BBB+
Senior secured debt	NSP-Minnesota	Aa3	A	A+
	NSP-Wisconsin	Aa3	A	A+
	PSCo	A1	A	A+
	SPS	A3	A	A-
Commercial paper	Xcel Energy Inc.	P-2	A-2	F2
	NSP-Minnesota	P-1	A-2	F2
	NSP-Wisconsin	P-1	A-2	F2
	PSCo	P-2	A-2	F2
	SPS	P-2	A-2	F2

2022 Financing Activity — During 2022, Xcel Energy plans to issue approximately \$75 to \$80 million of equity through the DRIP and benefit programs. In addition, Xcel Energy may issue up to \$800 million in equity from 2022-2026. Xcel Energy and its utility subsidiaries plan to issue the following:

Issuer	Security	Amount	Status
Xcel Energy	Unsecured Bonds	\$ 700	Planned - Q2
PSCo	First Mortgage Bonds	700	Planned - Q2
SPS	First Mortgage Bonds	200	Planned - Q2
NSP-Minnesota	First Mortgage Bonds	500	Planned - Q2
NSP-Wisconsin	First Mortgage Bonds	100	Planned - Q3

Financing plans are subject to change, depending on legislative initiatives (e.g., federal tax law changes), capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

Note 4. Rates, Regulation and Other

NSP-Minnesota — 2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.2%, a 52.50% equity ratio and forward test years. The request is detailed as follows:

(Amounts in Millions, Except Percentages)	2022	2023	2024	Total
Rate request	\$ 396	\$ 150	\$ 131	\$ 677
Increase percentage	12.2 %	4.8 %	4.2 %	21.2 %
Rate base	\$ 10,931	\$ 11,446	\$ 11,918	N/A

In December 2021, the MPUC approved interim rates, subject to refund, of \$247 million, effective Jan. 1, 2022. Next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Oct. 3, 2022.
- Rebuttal testimony: Nov. 8, 2022.
- Hearing: Dec. 13-16, 2022.
- Administrative Law Judge (ALJ) Report: March 31, 2023.
- MPUC Order: June 30, 2023.

NSP-Minnesota — 2022 Minnesota Natural Gas Rate Case — In November 2021, NSP-Minnesota filed a request with the MPUC for an annual natural gas rate increase of \$36 million, or 6.6%. The filing is based on a 2022 forecast test year and includes a requested ROE of 10.5%, an equity ratio of 52.5% and a rate base of \$934 million. In December 2021, the MPUC approved interim rates of \$25 million, subject to refund, effective Jan. 1, 2022. Next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Aug. 30, 2022.
- Rebuttal testimony: Oct. 4, 2022.
- Hearing: Nov. 1-4, 2022.
- ALJ Report: Feb. 6, 2023.
- MPUC Order: April 26, 2023.

NSP-Minnesota — 2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSA for a natural gas rate increase of \$7 million, or 10.5%. The filing is based on a requested ROE of 10.5%, an equity ratio of 52.54%, a 2022 forecast test year and a rate base of \$124 million. Interim rates of \$7 million, subject to refund, were implemented on Nov. 1, 2021.

In April 2022, NDPSA Staff recommended a \$4 million increase, based on an ROE of 9.5% and an equity ratio of 52.0%. In April 2022, NSP-Minnesota updated its request to \$6 million, or 8.8% based on a requested ROE of 10.5%, an equity ratio of 52.54% and an updated rate base of \$115 million. Hearings are expected June 1-3, 2022. An NDPSA decision is expected in the third quarter of 2022.

NSP-Minnesota — Minnesota Resource Plan Settlement — In July 2019, NSP-Minnesota filed its Minnesota (Upper Midwest) resource plan, which runs through 2034. In February 2022, the MPUC approved the following:

- 10-year extension for the Monticello nuclear facility.
- Retirement of the A.S. King plant in 2028 and Sherco 3 in 2030.
- NSP-Minnesota ownership of Sherco and A.S. King gen-tie lines plus additional renewable resources on the lines up to its current interconnection rights (2,000 MW for Sherco and 600 MW for A.S. King).
- The need for 2,150 MW of new wind and 2,500 MW of new solar by 2032, as well as additional renewable generation of 1,100 MW beyond 2032.
- Recognition of the need for 800 MW of additional firm dispatchable resources between 2027 and 2029. The dispatchable generation will require an approval through a certificate of need process.

NSP-Wisconsin — Michigan Electric Rate Case — In March 2022, the Michigan Public Service Commission approved an electric rate case settlement granting NSP-Wisconsin an electric revenue increase of \$1.6 million in 2022, based on a ROE of 9.7% and an equity ratio of 52.5%. New rates were effective April 1, 2022.

PSCo — Colorado Electric Rate Request — In July 2021, PSCo filed a request with the Colorado Public Utilities Commission (CPUC) seeking a net electric rate increase of \$343 million (or 12.4%). The total request reflects a \$470 million increase, which includes \$127 million of previously authorized costs currently recovered through various rider mechanisms. The request was based on a 10.0% ROE, an equity ratio of 55.64%, a 2022 forecast test year, a rate base of \$10.3 billion and impacts of a new depreciation study.

In March 2022, the CPUC approved an unopposed settlement without modification. Rates became effective April 1, 2022. Key settlement terms include:

- A net electric rate increase of \$177 million. The total change in base rates is \$299 million, which includes \$122 million of revenue previously collected through various rider mechanisms.
- A ROE of 9.3% and an equity ratio of 55.69%.
- A current 2021 test year (average rate base) with the transfer of Cheyenne Ridge, the Wildfire Mitigation Plan and Advanced Grid Intelligence and Security (AGIS) investments at year-end rate base.
- Approval of all of PSCo's proposed depreciation adjustments.
- Continuation of the property tax, qualified pension, and non-qualified pension trackers.
- Continuation of AGIS deferral including interest equivalent to PSCo's weighted average cost of capital once the balance exceeds \$50 million.
- Continuation of the Wildfire Mitigation Plan deferral, with a debt return.

PSCo — Resource Plan Settlement — In April 2022, PSCo and multiple intervenors filed a revised settlement of the resource plan, which will result in the further acceleration of the retirement of the Comanche Unit 3 coal plant, an expected carbon reduction of at least 85% and an 80% renewable mix by 2030. A CPUC decision is expected in the second quarter of 2022. Key settlement terms include:

- Early retirement of Hayden: Unit 2 in 2027 (was 2036); and Unit 1 in 2028 (was 2030).
- Conversion of the Pawnee coal plant to natural gas by no later than Jan. 1, 2026.
- Early retirement of Comanche Unit 3 by Jan. 1, 2031 with reduced operations beginning in 2025.
- Addition of ~2,400 MW of wind.
- Addition of ~1,600 MW of universal-scale solar.
- Addition of 400 MW of storage.
- Addition of 1,300 MW of flexible, dispatchable generation.
- Addition of ~1,200 MW of distributed solar resources through our renewable energy programs.

PSCo — Power Pathway Settlement — In February 2022, the CPUC approved the Certificate of Public Convenience and Necessity (CPCN) for the Pathway Project. Key decisions include:

- The CPUC approved PSCo's cost estimate of \$1.7 billion and recovery through the transmission rider.
- The CPUC modified the Performance Incentive Mechanism (PIM) proposed in the settlement agreement, which focused on cost controls, to add a separate mechanism to further incentivize timely delivery of the Pathway Project segments. Key details of the PIMs are pending the CPUC's written decision.
- The CPUC granted a conditional CPCN approval for the 345 kV May Valley-Longhorn line extension, pending the level of renewables being added in that region through PSCo's resource plan. The initial cost estimate for the extension is approximately \$250 million.

PSCo — Natural Gas Rate Case — In January 2022, PSCo filed a request with the CPUC seeking a net increase to retail natural gas rates of \$107 million. The total change to base rates is \$215 million, which reflects the transfer of \$108 million previously recovered from customers through the Pipeline System Integrity Adjustment (PSIA) rider. The request is based on a 10.25% ROE, an equity ratio of 55.66% and a 2022 current test year with a projected rate base of \$3.6 billion. PSCo has requested a proposed effective date of Nov. 1, 2022.

Additionally, PSCo's request includes step revenue increases of \$40 million (effective Nov. 1, 2023) and \$41 million (effective Nov. 1, 2024) related to continued capital investment.

Next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: June 15, 2022.
- Rebuttal testimony: July 13, 2022.
- Settlement: Aug. 3, 2022.
- Evidentiary hearings: Aug. 17-23, 2022.
- Statement of position: Sept. 21, 2022.

PSCo — Comanche Unit 3 Outage — In January 2022, PSCo experienced an extended outage at the Comanche Unit 3 plant (750 MW, coal-fueled electric generating unit). PSCo will not seek recovery of any incremental replacement power costs which are estimated to be \$25 million, assuming normal weather, current market pricing and remediation in June 2022. Incremental replacement power costs incurred as of March 31, 2022 were \$9 million.

SPS — New Mexico 2021 Electric Rate Case — In January 2021, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) with a current requested base rate increase of \$84 million.

In February 2022, the NMPRC approved an uncontested stipulation without modification, which reflected a \$62 million rate increase, a change in the depreciation life of the Tolk coal plant to 2032, an equity ratio of 54.72% and a ROE of 9.35% for reconciliation statements and determining the revenue requirements for the Sagamore and Hale wind projects. New rates went into effect on Feb. 26, 2022.

SPS — Texas 2021 Electric Rate Case — In 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately \$140 million. The request was based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately \$3.3 billion and a historic test year based on the 12-months ended Dec. 31, 2020.

In January 2022, SPS and intervenors filed a blackbox settlement. Key terms include:

- Base rate increase of \$89 million, effective back to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- Depreciation lives for Tolk moved up to 2034 and Harrington coal assets moved up to 2024.

In February 2022, the ALJ issued an order approving interim rates, effective March 1, 2022. A PUCT decision is expected in the second quarter of 2022.

Supply Chain

Xcel Energy's ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. Xcel Energy continues to monitor the availability of materials and has sought to mitigate impacts by seeking alternative suppliers as necessary.

Solar Resources

In April 2022, the U.S. Department of Commerce initiated an anti-circumvention investigation that would subject Crystalline Silicon Photovoltaic (CSPV) solar panels and cells imported from Malaysia, Vietnam, Thailand, and Cambodia with potential incremental tariffs ranging from 50% to 250%. These countries account for more than 80% of CSPV panel imports.

The uncertainty of the investigation and the adverse impact on potential tariffs has resulted in the cancellation or delay of certain domestic solar projects.

The impacts on Xcel Energy are as follows:

- *NSP-Minnesota Sherco Solar Project* — In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an initial estimated investment of approximately \$575 million. NSP-Minnesota requested a delay in the procedural schedule due to recent solar supply chain disruptions and potential impact on pricing. We now anticipate a MPUC decision in Q4 2022 or Q1 2023. The proposed facilities are still expected to be in-service by the end of 2025.
- *NSP-Wisconsin* — In June 2021, the PSCW approved NSP-Wisconsin's Western Mustang solar project, a 74 MW facility that would be built by a developer for approximately \$100 million. The project was originally scheduled to go into service in 2022. As a result of the disruption of the solar supply chain, the developer has indicated difficulty delivering the project at the contract price and scheduled in-service date. Negotiations on a potential solution are on-going.
- *PSCo PPAs* — PSCo has several solar PPAs scheduled to go into service in late 2022 and early 2023. Some developers have indicated difficulty delivering the projects at the contract price and at the scheduled in-service date. Negotiations on a potential solution are on-going. PSCo is developing contingency plans in the event that the PPAs are not completed in time to meet the capacity needs of the 2023 summer season.

Note 5. Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. As a result of the extremely high market prices, Xcel Energy incurred net natural gas, fuel and purchased energy costs of approximately \$1 billion.

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, the utility subsidiaries have deferred February 2021 cost increases for future recovery and sought recovery of the cost increases over a period of up to 63 months to mitigate the impact to customer bills. Additionally, we did not request recovery of financing costs in order to further limit the impact to our customers.

Xcel Energy currently has approval for recovery of Winter Storm Uri costs in Wisconsin, Michigan, North Dakota and New Mexico. There were no material costs for South Dakota. A summary of the pending regulatory requests for Winter Storm Uri cost recovery in the other states is listed below.

**Utility
Subsidiary Jurisdiction Regulatory Status**

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	<p>In 2021, the MPUC allowed recovery of \$179 million of costs (with no financing charge) starting in September 2021. The C&I class (\$82 million) will be recovered over 27 months and the residential class (\$97 million) will be recovered over a 63-month recovery period. The \$179 million in extraordinary cost recovery is subject to refund pending the outcome of a contested case before an ALJ.</p> <p>In December 2021, direct testimony was received from intervenors. A hearing before the ALJs took place in February 2022. The Company and intervenors subsequently submitted briefs. The Department of Commerce (DOC) recommended that NSP-Minnesota be disallowed \$122 million in costs. The Office of the Attorney General (OAG) modified its position, recommending disallowances of \$110 million to \$148 million, and the Citizens Utility Board (CUB) continues to recommend a \$69 million disallowance.</p> <p>Xcel Energy strongly disagrees with the recommendations of the DOC, OAG and CUB and believes that it acted prudently and according to MPUC approved procedures for the best interest of its customers and stakeholders. An ALJ decision is expected in late May and an MPUC decision is expected in Q3 of 2022.</p>
PSCo	Colorado	<p>In May 2021, PSCo filed a request with the CPUC to recover \$263 million in weather-related electric costs, \$287 million in incremental natural gas costs and \$4 million in incremental steam costs over 24 months with no financing charge.</p> <p>In October, a partial settlement was reached with the Staff and the Colorado Energy Office, allowing full recovery of Winter Storm Uri deferred costs of \$263 million (electric utility) and \$287 million (natural gas utility) over a 24-month and 30-month period, respectively, with no carrying charges. A CPUC decision on the settlement is pending.</p> <p>The statutory date for decision is July 15, 2022. In addition, the CPUC is considering prospective changes in fuel cost recovery.</p>
SPS	Texas	<p>In 2021, SPS filed to recover \$88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing.</p> <p>In January 2022, SPS and other parties filed a stipulation for interim rates. The filing covers all fuel under-collections occurring between January 2020 and August 2021, totaling \$121 million. The settlement does not address the prudence of Winter Storm Uri costs nor the retention of \$11 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision. Interim rates, designed to collect up to \$110 million over a period of 30 months, began on Feb. 1, 2022.</p>

Note 6. Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2022 Earnings Guidance — Xcel Energy’s 2022 GAAP and ongoing earnings guidance is a range of \$3.10 to \$3.20 per share.^(a)

Key assumptions as compared with 2021 levels unless noted:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to increase ~1% to 2%.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%.
- Capital rider revenue is projected to increase \$0 million to \$10 million (net of PTCs). The change in the capital rider assumption reflects an increase in the PTC rate, as published by the IRS in April 2022, and will not materially impact earnings as it will be offset by lower tax expense. PTCs are credited to customers through capital riders and reductions to other regulatory mechanisms.
- O&M expenses are projected to increase approximately 1%.
- Depreciation expense is projected to increase approximately \$285 million to \$295 million. The change in assumption is a result of new rates going into effect in Colorado and New Mexico for changes in depreciation lives and will be offset by revenue with minimal impact on earnings.
- Property taxes are projected to increase approximately \$40 million to \$50 million.
- Interest expense (net of AFUDC - debt) is projected to increase \$80 million to \$90 million. The assumption change reflects higher interest rates and slightly larger debt issuances.
- AFUDC - equity is projected to be relatively flat.
- ETR is projected to be ~(6%) to (8%). The change in the ETR assumption reflects an increase in the PTC rate, as published by the IRS in April 2022. The impacts of PTCs are credited to customers through electric margin and will not have a material impact on net income.

^(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management’s view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing EPS to corresponding GAAP EPS.

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5% to 7% based off of a 2021 base of \$2.96 per share, which represents the mid-point of the revised 2021 guidance range of \$2.94 to \$2.98 per share.
- Deliver annual dividend increases of 5% to 7%.
- Target a dividend payout ratio of 60% to 70%.
- Maintain senior secured debt credit ratings in the A range.

XCEL ENERGY INC. AND SUBSIDIARIES
EARNINGS RELEASE SUMMARY (UNAUDITED)
(amounts in millions, except per share data)

	Three Months Ended March 31	
	2022	2021
Operating revenues:		
Electric and natural gas	\$ 3,723	\$ 3,517
Other	28	24
Total operating revenues	3,751	3,541
Net income	\$ 380	\$ 362
Weighted average diluted common shares outstanding	545	539
Components of EPS — Diluted		
Regulated utility	\$ 0.75	\$ 0.73
Xcel Energy Inc. and other costs	(0.05)	(0.06)
GAAP and ongoing diluted EPS ^{(a)(b)}	\$ 0.70	\$ 0.67
Book value per share	\$ 28.86	\$ 27.29
Cash dividends declared per common share	0.4875	0.4575

^(a) For the three months ended March 31, 2022, there were no adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

^(b) Amounts may not add due to rounding.