Exhibit 99.01

April 29, 2021

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
FIRST QUARTER 2021 EARNINGS REPORT

- GAAP 2021 first quarter EPS was $0.67 compared with $0.56 in 2020.
- Xcel Energy reaffirms 2021 EPS earnings guidance of $2.90 to $3.00.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2021 first quarter GAAP and ongoing earnings of $362 million, or $0.67 per share, compared with $295 million, or $0.56 per share in the same period in 2020.

Earnings reflect higher electric and natural gas margins, which more than offset additional depreciation, interest charges and less allowance for funds used during construction (AFUDC).

"Xcel Energy had a strong first quarter and we are reaffirming our expectation to deliver earnings within our annual guidance range," said Ben Fowke, chairman and CEO. "We are also pleased to have achieved a significant milestone, reducing carbon emission 51% from 2005 levels, bringing us more than halfway to our vision of delivering 100% carbon-free electricity to our customers by 2050."

"We recently proposed significant measures in Colorado that will transform the energy landscape and help the state continue its clean energy leadership. Our Colorado Clean Energy Plan adds more than 5,000 megawatts of renewable energy and accelerates the retirement of our coal plants. The plan will reduce carbon emissions 85% in Colorado and increase renewable energy to nearly 80% by 2030. To support this ambitious plan, we also proposed a significant transmission expansion that would add 560 miles of new lines to deliver renewable energy."

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:	(888) 394-8218
International Dial-In:	(400) 120-9101
Conference ID:	7731118

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 Investor Relations. 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 29 through 12:00 p.m. CDT on May 2.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	7731118

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 the 2021 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, 2020 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; operational safety, including our nuclear generation facilities; 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; 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 and their impact on capital expenditures and 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; and costs of potential regulatory penalties.

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

	Three Months Ended March 31	
	2021	**2020**
Operating revenues		
Electric	$ 2,870	$ 2,203
Natural gas	647	583
Other	24	25
Total operating revenues	3,541	2,811
Operating expenses		
Electric fuel and purchased power	1,386	797
Cost of natural gas sold and transported	299	285
Cost of sales — other	8	9
Operating and maintenance expenses	584	579
Conservation and demand side management expenses	73	74
Depreciation and amortization	521	463
Taxes (other than income taxes)	163	149
Total operating expenses	3,034	2,356
Operating income	507	455
Other income (expense), net	5	(11)
Equity earnings of unconsolidated subsidiaries	14	11
Allowance for funds used during construction — equity	14	23
Interest charges and financing costs		
Interest charges — includes other financing costs of $7 and $7, respectively	205	199
Allowance for funds used during construction — debt	(5)	(10)
Total interest charges and financing costs	200	189
Income before income taxes	340	289
Income tax benefit	(22)	(6)
Net income	$ 362	$ 295
Weighted average common shares outstanding:		
Basic	538	526
Diluted	539	527
Earnings per average common share:		
Basic	$ 0.67	$ 0.56
Diluted	0.67	0.56

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), electric margin, natural gas margin, 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 excludes (or includes) amounts that are adjusted from 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.

<u>Ongoing ROE</u>
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.

<u>Electric and Natural Gas Margins</u>
Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales - other, operating and maintenance (O&M) expenses, conservation and demand side management (DSM) expenses, depreciation and amortization and taxes (other than income taxes).

<u>Earnings Adjusted for Certain Items (Ongoing Earnings and Ongoing Diluted EPS)</u>
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 is calculated by dividing the net income or loss of each subsidiary, 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 of 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, 2021 and 2020, 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 2021 first quarter earnings were $0.67 per share compared to $0.56 per share in 2020, primarily reflecting higher electric and natural gas margins (driven by capital investment recovery and regulatory outcomes), which more than offset additional depreciation, interest charges, less AFUDC and declining sales primarily due to the impacts of COVID-19. First quarter earnings also reflect margin from proprietary commodity trading transactions, primarily entered into under Xcel Energy’s ordinary practices prior to the weather event. See Note 5 for further discussion.

Summarized diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	**2021**	**2020**
PSCo	$ 0.31	$ 0.24
NSP-Minnesota	0.24	0.20
SPS	0.11	0.08
NSP-Wisconsin	0.06	0.06
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility [(a)]	0.73	0.60
Xcel Energy Inc. and Other	(0.06)	(0.04)
Total [(a)]	**$ 0.67**	**$ 0.56**

[(a)] Amounts may not add due to rounding.

PSCo — Earnings increased $0.07 per share for the first quarter of 2021, reflecting higher natural gas and electric margins (primarily capital investment recovery and regulatory outcomes), partially offset by additional depreciation and taxes (other than income taxes).

NSP-Minnesota — Earnings increased $0.04 per share for the first quarter of 2021, reflecting higher electric margin (primarily capital investment recovery), partially offset by increased depreciation.

SPS — Earnings increased $0.03 per share for the first quarter of 2021, reflecting higher electric margin (regulatory outcomes in Texas and New Mexico), partially offset by increased depreciation.

NSP-Wisconsin — Earnings were flat for the first quarter of 2021.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company.

Components significantly contributing to changes in 2021 EPS compared to 2020:

Diluted Earnings (Loss) Per Share	**Three Months Ended March 31**
GAAP and ongoing diluted EPS - 2020	**$ 0.56**
Components of change - 2021 vs. 2020	
Higher electric margin	0.11
Higher natural gas margins	0.07
Lower ETR [(a)]	0.06
Higher other income (expense), net	0.02
Higher depreciation and amortization	(0.08)
Lower AFUDC	(0.02)
Higher interest charges	(0.01)
Higher O&M	(0.01)
Other, net	(0.03)
GAAP and ongoing diluted EPS - 2021	**$ 0.67**

[(a)] Includes production tax credits (PTCs) and plant regulatory amounts, which are primarily offset in electric margin.

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.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather. Typically, sales are not impacted in the first or fourth quarter due to THI or CDD.

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.

Percentage increase (decrease) in normal and actual HDD:

	Three Months Ended March 31		
	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
HDD	1.3 %	(5.5)%	6.5 %

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

	Three Months Ended March 31		
	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
Retail electric	$ —	$ (0.011)	$ 0.011
Decoupling and sales true-up	0.002	0.006	(0.004)
Electric total	$ 0.002	$ (0.005)	$ 0.007
Firm natural gas	0.003	(0.007)	0.010
Total	$ 0.005	$ (0.012)	$ 0.017

Sales — Sales growth (decline) for actual and weather-normalized sales in 2021 compared to 2020:

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual [(a)]					
Electric residential	6.3 %	5.1 %	8.8 %	4.7 %	6.0 %
Electric C&I	(4.8)	(6.6)	(7.1)	(1.8)	(5.8)
Total retail electric sales	(1.0)	(2.9)	(4.3)	0.2	(2.4)
Firm natural gas sales	4.7	0.5	N/A	0.8	3.1

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized [(a)]					
Electric residential	4.9 %	4.5 %	3.8 %	2.9 %	4.4 %
Electric C&I	(5.1)	(6.7)	(7.3)	(1.9)	(6.0)
Total retail electric sales	(1.7)	(3.1)	(5.4)	(0.4)	(3.0)
Firm natural gas sales	(0.9)	(1.3)	N/A	(2.7)	(1.2)

	Three Months Ended March 31 (2020 Leap Year Adjusted)				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized [(a)]					
Electric residential	6.1 %	5.7 %	5.0 %	4.0 %	5.6 %
Electric C&I	(4.1)	(5.6)	(6.3)	(0.8)	(5.0)
Total retail electric sales	(0.6)	(2.0)	(4.3)	0.7	(1.9)
Firm natural gas sales	0.2	(0.2)	N/A	(1.5)	—

[(a)] Higher residential sales and lower commercial and industrial (C&I) sales were primarily attributable to COVID-19.

Weather-normalized and leap-year adjusted electric sales growth (decline) — year-to-date (excluding leap day)

Each of our utility subsidiaries experienced higher residential sales and lower C&I sales as a result of COVID-19 beginning in March 2020. In addition, the following items impacted sales:

- PSCo — Residential sales rose based on an increased number of customers and higher use per customer. The decline in C&I sales was primarily due to decreases in the manufacturing and service industries, partially offset by an increase in the energy sector.
- NSP-Minnesota — Residential sales growth reflects higher use per customer and increased customer additions. The decline in C&I sales was primarily due to decreases within the manufacturing and service sectors.
- SPS — Residential sales increased due to customer growth and higher use per customer. The decline in C&I sales was driven by decreases within the energy and manufacturing sectors.
- NSP-Wisconsin — Residential sales growth was attributable to customer additions and higher use per customer. The decline in C&I sales was largely related to decreases in the energy and manufacturing industries, partially offset by an increase in the service sector.

Weather-normalized and leap-year adjusted natural gas sales growth (decline) — year-to-date (excluding leap day)

- Natural gas sales primarily reflect lower customer use, offset by an increase in the number of customers.

Electric Margin — 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 have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated, which reduced electric revenue and margin. See Note 5 for discussion on the impact of Winter Storm Uri.

Electric revenues and margin:

(Millions of Dollars)	Three Months Ended March 31 2021	2020
Electric revenues	$ 2,870	$ 2,203
Electric fuel and purchased power	(1,386)	(797)
Electric margin	$ 1,484	$ 1,406

Changes in electric margin:

(Millions of Dollars)	Three Months Ended March 31, 2021 vs. 2020
Non-fuel riders	$ 44
Regulatory rate outcomes (Colorado, Texas, New Mexico, Wisconsin and North Dakota)	44
Proprietary commodity trading, net of sharing (see Note 5)	27
Wholesale transmission revenue (net)	11
Estimated impact of weather (net of decoupling/sales true-up)	5
PTCs flowed back to customers (offset by lower ETR)	(37)
Sales and demand [(a)]	(14)
Other (net)	(2)
Total increase in electric margin	$ 78

[(a)] Sales excludes weather impact, net of decoupling/sales true-up, and demand is net of sales true-up.

Natural Gas Margin — Natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to cost recovery mechanisms. See Note 5 for discussion on the impact of Winter Storm Uri.

Natural gas revenues and margin:

(Millions of Dollars)	Three Months Ended March 31 2021	2020
Natural gas revenues	$ 647	$ 583
Cost of natural gas sold and transported	(299)	(285)
Natural gas margin	$ 348	$ 298

Changes in natural gas margin:

(Millions of Dollars)	Three Months Ended March 31, 2021 vs. 2020
Regulatory rate outcomes (Colorado)	$ 40
Estimated impact of weather	7
Other (net)	3
Total increase in natural gas margin	$ 50

O&M Expenses — O&M expenses increased $5 million, or 0.9%, for the first quarter of 2021. The increase was primarily due to expenses associated with new wind farms, software and infrastructure costs, compensation, damage prevention and storms, partially offset by continuous improvement initiatives.

Depreciation and Amortization — Depreciation and amortization increased $58 million, or 12.5%, for the first quarter of 2021. The increase was primarily driven by several wind farms going into service, as well as normal system expansion. In addition, 2021 depreciation expense increased as a result of implementation of new depreciation rates in Colorado, New Mexico and Texas.

Other Income (Expense) — Other income (expense) increased $16 million for the first quarter of 2021, largely related to rabbi trust performance primarily offset in O&M expenses (compensation).

AFUDC, Equity and Debt — AFUDC decreased $14 million for the first quarter of 2021. Decrease was driven by various wind projects placed into service.

Interest Charges — Interest charges increased $6 million, or 3.0%, for the first quarter of 2021. The increase was largely attributable to higher debt levels to fund capital investments, partially offset by lower long-term and short-term interest rates.

Income Taxes — Effective income tax rate:

	Three Months Ended March 31 2021	2020	2021 vs 2020
Federal statutory rate	21.0 %	21.0 %	— %
State tax (net of federal tax effect)	4.9	4.9	—
(Decreases) increases:			
Wind PTCs	(24.6)	(17.2)	(7.4)
Plant regulatory differences [a]	(6.1)	(8.4)	2.3
Other (net)	(1.7)	(2.4)	0.7
Effective income tax rate	(6.5)%	(2.1)%	(4.4)%

[a] Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers. Income tax benefits associated with the credit of excess deferred credits are generally offset by corresponding revenue reductions.

Income tax benefit increased $16 million for the first quarter of 2021. The increase was primarily driven by an increase in wind PTCs due to additional wind facilities going into service. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. Impact of wind PTCs was partially offset by higher pretax earnings in 2021.

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

Xcel Energy's capital structure:

(Millions of Dollars)	March 31, 2021	Percentage of Total Capitalization	Dec. 31, 2020	Percentage of Total Capitalization
Current portion of long-term debt	$ 21	— %	$ 421	1 %
Short-term debt	1,477	4	584	2
Long-term debt	21,470	57	19,645	56
Total debt	22,968	61	20,650	59
Common equity	14,700	39	14,575	41
Total capitalization	$ 37,668	100 %	$ 35,225	100 %

Liquidity — As of April 26, 2021, 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	$ 200	$ 1,050	$ 3	$ 1,053
PSCo	700	8	692	144	836
NSP-Minnesota	500	10	490	518	1,008
SPS	500	2	498	43	541
NSP-Wisconsin	150	—	150	2	152
Total	$ 3,100	$ 220	$ 2,880	$ 710	$ 3,590
Term Loan [(c)]	1,200	1,200	—		

(a) Expires June 2024.
(b) Includes outstanding commercial paper and letters of credit.
(c) Matures February 2022.

Term Loan Agreements — In February 2021, Xcel Energy Inc. entered into a $1.2 billion 364-Day Term Loan Agreement in order to enhance liquidity due to the incremental fuel costs from Winter Storm Uri and potential regulatory lag in recovery. See Note 5 for further discussion.

Bilateral Credit Agreement — In April 2021, NSP-Minnesota extended an uncommitted bilateral credit agreement of $75 million, which is limited in use to support letters of credit for one-year. NSP-Minnesota had $49 million of outstanding letters of credits as of March 31, 2021.

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 26, 2021:

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

2021 Financing Activity — During 2021, Xcel Energy plans to issue approximately $75 to $80 million of equity through the DRIP and benefit programs. In addition, Xcel Energy Inc. and its utility subsidiaries issued or anticipate issuing the following:

Issuer	Security	Amount	Status	Tenor	Coupon
PSCo	First Mortgage Bonds	$ 750	Completed	10 Year	1.875 %
SPS	First Mortgage Bonds	250	Completed	29 Year	3.15
NSP-Minnesota	First Mortgage Bonds	425	Completed	10 Year	2.25
NSP-Minnesota	First Mortgage Bonds	425	Completed	31 Year	3.20
NSP-Wisconsin	First Mortgage Bonds	125	Planned - Q2	N/A	N/A

Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

Note 4. Rates and Regulation

NSP-Minnesota — Minnesota Relief and Recovery — Recent proposals include:

- In February 2021, NSP-Minnesota proposed to acquire a 120 MW repowered wind farm from ALLETE for $210 million. A MPUC decision was requested by July 29, 2021.
- In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an incremental investment of $575 million. A MPUC decision is expected in the second half of 2021.

NSP-Minnesota — 2020 North Dakota Electric Rate Case — In November 2020 and revised in March 2021, NSP-Minnesota filed a rate case with the North Dakota Public Service Commission (NDPSC). NSP-Minnesota is requesting an increase in annual retail electric revenues of approximately $19 million. The rate filing is based on a 2021 forecast test year, a requested ROE of 10.2%, an equity ratio of 52.5% and an electric rate base of approximately $677 million. Interim rates, subject to refund, of approximately $16 million were implemented in January 2021 and subsequently revised to $13 million, effective April 1, 2021.

PSCo — Wildfire Protection Rider — In 2020, PSCo requested to establish a rider to recover incremental costs associated with system investments to reduce wildfire risk, projected to be approximately $325 million from 2021 through 2025. In February 2021, the administrative law judge (ALJ) issued a recommended decision approving the wildfire mitigation program as it was in the public's interest, but denied PSCo's rider request in favor of deferred accounting with ultimate recovery in a future rate case. In April 2021, the CPUC accepted the ALJ's recommended decision.

Forecasted annual revenue requirements from 2021 through 2025:

(Millions of Dollars)	2021	2022	2023	2024	2025
Forecasted annual revenue requirement	$ 17	$ 24	$ 29	$ 32	$ 34

PSCo — Pipeline System Integrity Adjustment (PSIA) Rider Extension — In February 2021, PSCo requested to extend its PSIA rider for three years (through the end of 2024). The extension is intended to allow for a wind down of the rider and transition of recovery of the projects included in the rider to base rates in 2025. A CPUC decision is expected in the fourth quarter of 2021.

PSCo — Colorado's Power Pathway Transmission Expansion — In March 2021, PSCo filed for a Certificate of Public Convenience and Necessity for the Power Pathway transmission project. Xcel Energy proposed a 560-mile, 345 kV double circuit transmission network to enable 5,500 MW of renewable generation in eastern Colorado with an estimated cost of approximately $1.7 billion. PSCo also presented an extension of the Power Pathway project into southeast Colorado, referred to as the May Valley - Longhorn Extension ($0.3 billion). PSCo expects future filings for related network upgrades, voltage support and interconnection facilities, which with the May Valley - Longhorn Extension, could result in an incremental investment of $0.5 - $1 billion. A CPUC decision regarding the Power Pathway project, as well as the May Valley - Longhorn Extension, is expected in late 2021.

PSCo** — **Electric Resource Plan — In March 2021, PSCo filed its 2021 Electric Resource Plan with the CPUC. The filing outlines the proposed future retirements/conversions of PSCo's remaining coal plants and would result in an 80% renewable fuel mix and an 85% carbon emissions reduction target by 2030.

Major components of PSCo's proposed preferred plan include:

- Early retirement of Comanche Generating Station: Unit 3 in 2040 (currently 2070).
- Early retirement of Hayden Generating Station: Unit 1 in 2028 (currently 2030); Unit 2 in 2027 (currently 2036).
- Conversion of Pawnee Generating Station from coal to natural gas in 2028 with retirement in 2041.
- 2,300 megawatts of wind power.
- 1,600 megawatts of large-scale solar power.
- 400 megawatts of energy storage.
- 1,300 megawatts of flexible dispatchable resources (including natural gas).
- 1,200 megawatts of distributed generation solar resources.

The preferred plan proposes to create a regulatory asset to recover costs over their original depreciation lives for the Hayden power plant and the coal handling equipment at Pawnee. It also proposes the use of securitization to finance and recover the remaining book life and decommissioning costs for Comanche 3 upon retirement in 2040.

A CPUC decision on the resource plan is expected by the end of 2021 (Phase I) with the competitive solicitation for resource additions expected in 2022 (Phase II). Incremental generation system costs to meet carbon emission reduction targets are proposed to be recovered through a statutorily-authorized Clean Energy Plan Rider.

SPS — New Mexico 2021 Electric Rate Case — In January 2021, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) seeking an increase in base rates of approximately $88 million. SPS' net rate increase to New Mexico customers is expected to be approximately $48 million, or 10%, as a result of offsetting fuel cost reductions and PTCs from the Sagamore wind project. PTCs are being credited to customers through the fuel clause.

The request is based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and a retail rate base of approximately $1.9 billion.

The request includes the effect of approximately 400 MW of reduced peak load in 2021 from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk coal-fired power plant (from 2037 to 2032) and the coal handling assets at the Harrington facility (to 2024).

Procedural schedule expected to be as follows:

- Staff and intervenor testimony — May 17, 2021.
- Rebuttal testimony — June 9, 2021.
- Deadline to file stipulation — June 23, 2021.
- Public hearing or hearing on stipulation — July 26 - Aug. 6, 2021.
- End of nine month suspension — Nov. 3, 2021.

A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

SPS — Texas 2021 Electric Rate Case — In February 2021, SPS filed an electric rate case with the Public Utilities Commission of Texas (PUCT) and its municipalities with original rate jurisdiction seeking an increase in base rates of approximately $143 million. SPS' net rate increase to Texas customers is expected to be approximately $74 million, or 9.2%, as a result of offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on an ROE of 10.35%, an equity ratio of 54.60% (based on actual capital structure), a Texas retail rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020.

The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and the coal handling assets of the Harrington facility (to 2024).

Procedural schedule expected to be as follows:

- Intervenor testimony — Aug. 13, 2021.
- Staff testimony — Aug. 20, 2021.
- Rebuttal testimony — Sept. 15, 2021.
- Public hearing — Oct. 18 - Oct. 28, 2021.

Once final rates are approved, a surcharge will be requested from March 15, 2021 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2022.

Note 5. Winter Storm Uri

In mid-February 2021, the central portion of the United States experienced a major winter storm (Winter Storm Uri). Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation across the region. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. In addition, NSP-Minnesota's three peak shaving plants, which are used to ensure system reliability under Design Day conditions, have been unavailable since early 2021 due to required repairs to address safety concerns with the units. Despite the extreme conditions, Xcel Energy's customers experienced minimal disruptions as a result of preemptive infrastructure investments and the response of our employees.

As a result of the extremely high market prices, Xcel Energy incurred net natural gas, fuel and purchased energy costs of approximately $965 million (largely deferred as regulatory assets). The utility subsidiaries mitigated the customer impact by approximately $190 million primarily through sales of excess generation.

The estimated net impact was as follows:

(in millions)	Natural Gas for Distribution	Natural Gas for Electric Generation	Other Electric Generation	Subtotal Costs	Net Market Settlements [a]	Total Impact
NSP-Minnesota	$ 250	$ 5	$ 15	$ 270	$ (40)	$ 230
NSP- Wisconsin	45	—	—	45	—	45
PSCo	305	315	5	625	(15)	610
SPS	—	200	15	215	(135)	80
Total	$ 600	$ 520	$ 35	$ 1,155	$ (190)	$ 965

[a] Net market settlements includes purchases of energy and other charges to serve our customers as well as sales of energy facilitated through Independent System Operators (ISOs) or bilateral transactions, each subject to mechanisms for recovery and sharing with our customers.

In addition, higher market prices resulted in $27 million of net gains (after customer sharing) related to proprietary commodity trading. These transactions were primarily entered into under Xcel Energy's ordinary trading practices prior to Winter Storm Uri.

Certain energy transactions are subject to final ISO re-settlement calculations and the impacts of credit losses shared among market participants. Such adjustments are not expected to be material to our results of operations, financial condition or cash flows.

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for the purpose of recovering incurred costs. However, the utility subsidiaries have deferred February cost increases for future recovery and are proposing to recover the cost increases over a period of up to two years in order to significantly mitigate the impact to customer bills. Additionally, we are not requesting recovery of associated financing costs in order to further limit the impact to our customers. The following proceedings have been initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	NSP-Minnesota has filed its report with the MPUC detailing its preparedness and actions during the storm and proposing recovery of incremental costs from natural gas customers over 24 months with no financing charge. Comments are due in May 2021.
	South Dakota	In April, NSP-Minnesota filed a letter with the South Dakota Public Utilities Commission noting that we were a net seller in the market, resulting in lower fuel clause costs.
	North Dakota	NSP-Minnesota has filed its report with the NDPSC detailing its preparedness and actions during the storm and proposing recovery of incremental costs from natural gas customers over 24 months with no financing charge.
NSP-Wisconsin	Wisconsin	In March, the Public Service Commission of Wisconsin staff determined the natural gas costs incurred during the storm were prudent and approved NSP-Wisconsin's proposal to recover these costs over a nine-month period through December 2021 with no financing charge.
	Michigan	In March, NSP-Wisconsin filed testimony in the pending gas recovery plan proceeding to address $2 million of under-recovery associated with Winter Storm Uri.
PSCo	Colorado	PSCo filed an initial response with the CPUC in March. In May 2021, PSCo intends to file a plan to recover the weather-related costs over 24 months with no financing charge.
SPS	Texas	SPS intends to file for a surcharge in the second quarter to recover fuel costs over 24 months with no financing charge. Prudence of fuel costs will be subject to review in SPS' upcoming fuel reconciliation case.
	New Mexico	The NMPRC approved SPS' requested fuel mechanism variance to permit recovery over 24 months with no financing charge (subject to NMPRC review).

To enhance liquidity and for the ability to propose recovering the increased fuel costs over a longer time period (i.e., mitigate customer bill impacts), Xcel Energy Inc. entered into a $1.2 billion 364-Day Term Loan Agreement and increased the size of its previously planned debt issuances at the utility subsidiaries.

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

Xcel Energy 2021 Earnings Guidance — Xcel Energy's 2021 GAAP and ongoing earnings guidance is a range of $2.90 to $3.00 per share.[(a)]

Key assumptions as compared with 2020 levels unless noted:

- Constructive outcomes in all rate case and regulatory proceedings.
- Modest impacts from COVID-19.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to increase ~1%.
- Weather-normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase $100 million to $110 million (net of PTCs). PTCs are credited to customers, through capital riders, fuel clause or base rates and results in a reduction to electric margin.
- O&M expenses are projected to be relatively flat.
- Depreciation expense is projected to increase approximately $155 million to $165 million. The change in depreciation expense is largely earnings neutral and primarily reflects the timing of deferrals and revenue recognition in the Texas rate case.
- Property taxes are projected to increase approximately $40 million to $50 million.
- Interest expense (net of AFUDC - debt) is projected to increase $20 million to $30 million.
- AFUDC - equity is projected to decline approximately $40 million to $50 million.
- ETR is projected to be (7%) to (8%). The ETR reflects benefits of PTCs which 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 2020 base of $2.78 per share, which represents the mid-point of the original 2020 guidance range of $2.73 to $2.83 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	
	2021	**2020**
Operating revenues:		
Electric and natural gas	$ 3,517	$ 2,786
Other	24	25
Total operating revenues	3,541	2,811
Net income	$ 362	$ 295
Weighted average diluted common shares outstanding	539	527
Components of EPS — Diluted		
Regulated utility	$ 0.73	$ 0.60
Xcel Energy Inc. and other costs	(0.06)	(0.04)
GAAP and ongoing diluted EPS [a][b]	**$ 0.67**	**$ 0.56**
Book value per share	$ 27.29	$ 25.26
Cash dividends declared per common share	0.46	0.43

[a] For the three months ended March 31, 2021, 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.