Exhibit 99.01

Xcel Energy®

October 28, 2021

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
THIRD QUARTER 2021 EARNINGS REPORT

- Third quarter GAAP diluted earnings per share were $1.13 in 2021 compared with $1.14 in 2020.
- Year-to-date GAAP diluted earnings per share for 2021 were $2.38 compared with $2.25 in 2020.
- Xcel Energy narrows its 2021 EPS earnings guidance range to $2.94 to $2.98 from $2.90 to $3.00.
- Xcel Energy initiates 2022 EPS earnings guidance of $3.10 to $3.20.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2021 third quarter GAAP and ongoing earnings of $609 million, or $1.13 per share, compared with $603 million, or $1.14 per share in the same period in 2020.

Earnings reflect higher electric and natural gas margins and lower operating and maintenance (O&M) expenses, which were offset by additional depreciation and lower allowance for funds used during construction (AFUDC).

“Xcel Energy posted strong year-to-date results, so we’re narrowing our 2021 earnings guidance to $2.94 to $2.98 per share. We are also issuing an updated capital forecast of $26 billion for 2022 to 2026, which will provide significant benefits to our customers, help us to achieve our goal of an 80% reduction in CO_2 emissions from 2005 levels by 2030 and a carbon free electric system by 2050, and drive rate base growth of 6.5%. In addition, we are initiating 2022 earnings guidance of $3.10 to $3.20 per share, which is consistent with our long-term growth objective,” said Bob Frenzel, president and CEO of Xcel Energy.

“I’m also pleased the company is delivering on our vision to power 1.5 million electric vehicles by 2030. We just unveiled a suite of EV charging programs for our customers in Colorado that will make it easier, faster and more affordable for customers to charge their EVs, including those living in multifamily buildings. That program is one of the reasons that we were proud to have President Biden recognize Xcel Energy’s clean energy leadership during his visit to the National Renewable Energy Laboratory last month.”

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) 204-4368
International Dial-In:	(400) 120-9101
Conference ID:	5692678

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 Oct. 28 through 12:00 p.m. CDT on Oct. 31.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	5692678

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 and 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, 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, 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; and costs of potential regulatory penalties.

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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 Sept. 30		Nine Months Ended Sept. 30	
	2021	2020	2021	2020
Operating revenues				
Electric	$ 3,176	$ 2,941	$ 8,643	$ 7,430
Natural gas	268	219	1,364	1,082
Other	23	22	69	67
Total operating revenues	3,467	3,182	10,076	8,579
Operating expenses				
Electric fuel and purchased power	1,210	981	3,643	2,611
Cost of natural gas sold and transported	86	54	603	425
Cost of sales — other	11	11	28	28
Operating and maintenance expenses	568	579	1,752	1,708
Conservation and demand side management expenses	78	73	222	215
Depreciation and amortization	537	513	1,586	1,449
Taxes (other than income taxes)	152	158	472	453
Total operating expenses	2,642	2,369	8,306	6,889
Operating income	825	813	1,770	1,690
Other (expense) income, net	(3)	1	5	(6)
Earnings from equity method investments	13	12	47	29
Allowance for funds used during construction — equity	21	30	53	91
Interest charges and financing costs				
Interest charges — includes other financing costs of $7, $7, $22 and $21, respectively	211	221	628	628
Allowance for funds used during construction — debt	(7)	(11)	(18)	(33)
Total interest charges and financing costs	204	210	610	595
Income before income taxes	652	646	1,265	1,209
Income tax expense (benefit)	43	43	(17)	24
Net income	$ 609	$ 603	$ 1,282	$ 1,185
Weighted average common shares outstanding:				
Basic	539	526	539	526
Diluted	539	528	539	527
Earnings per average common share:				
Basic	$ 1.13	$ 1.15	$ 2.38	$ 2.25
Diluted	1.13	1.14	2.38	2.25

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), 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 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.

Electric and Natural Gas Margins
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, O&M expenses, conservation and demand side management (DSM) expenses, depreciation and amortization and taxes (other than income taxes).

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 and nine months ended Sept. 30, 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 third quarter diluted earnings were $1.13 per share in 2021, compared with $1.14 in 2020. Higher depreciation and lower AFUDC were partially offset by higher electric and natural gas margins (driven by capital investment recovery and other regulatory outcomes) and lower O&M expenses.

Summarized diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2021**	**2020**	**2021**	**2020**
PSCo	$ 0.40	$ 0.42	$ 0.96	$ 0.87
NSP-Minnesota	0.46	0.46	0.91	0.89
SPS	0.25	0.24	0.48	0.46
NSP-Wisconsin	0.07	0.08	0.15	0.16
Earnings from equity method investments — WYCO	0.01	0.01	0.03	0.04
Regulated utility [(a)]	1.19	1.21	2.54	2.42
Xcel Energy Inc. and Other	(0.06)	(0.07)	(0.16)	(0.17)
Total [(a)]	**$ 1.13**	**$ 1.14**	**$ 2.38**	**$ 2.25**

(a) Amounts may not add due to rounding.

PSCo — Earnings decreased $0.02 per share for the third quarter of 2021 and increased $0.09 per share year-to-date. The increase in year-to-date earnings reflects higher natural gas and electric margins (regulatory outcomes to primarily recover capital investments), partially offset by additional depreciation, O&M expenses and other taxes (other than income taxes).

NSP-Minnesota — Earnings were flat for the third quarter of 2021 and increased $0.02 per share year-to-date. The increase in year-to-date earnings reflects higher electric margin (regulatory outcomes to primarily recover capital investments), partially offset by increased depreciation and O&M expenses.

SPS — Earnings increased $0.01 per share for the third quarter of 2021 and $0.02 per share year-to-date. The increase in year-to-date earnings reflects higher electric margin (capital investment recovery and regulatory outcomes), partially offset by decreased AFUDC.

NSP-Wisconsin — Earnings decreased $0.01 per share for the third quarter of 2021 and $0.01 year-to-date. The decrease in year-to-date earnings is largely driven by higher O&M expenses and income tax expense, partially offset by higher electric margin and lower depreciation.

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 2021 EPS compared to 2020:

Diluted Earnings (Loss) Per Share	**Three Months Ended Sept. 30**	**Nine Months Ended Sept. 30**
GAAP and ongoing diluted EPS — 2020	**$ 1.14**	**$ 2.25**
Components of change - 2021 vs. 2020		
Higher electric margin	0.01	0.25
Higher natural gas margins	0.03	0.15
Lower Effective Tax Rate (ETR) [(a)]	0.01	0.12
Higher other (expense) income, net	(0.01)	0.02
Lower interest charges	0.01	—
Lower (Higher) O&M expenses	0.02	(0.06)
Lower AFUDC	(0.02)	(0.09)
Higher depreciation and amortization	(0.03)	(0.19)
Other, net	(0.03)	(0.07)
GAAP and ongoing diluted EPS — 2021	**$ 1.13**	**$ 2.38**

[(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. However, sales true-up and decoupling mechanisms in Minnesota and Colorado predominately mitigate the positive and adverse impacts of weather.

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 Sept. 30			**Nine Months Ended Sept. 30**		
	2021 vs. Normal	**2020 vs. Normal**	**2021 vs. 2020**	**2021 vs. Normal**	**2020 vs. Normal**	**2021 vs. 2020**
Retail electric	$ 0.067	$ 0.079	$ (0.012)	$ 0.122	$ 0.096	$ 0.026
Decoupling and sales true-up	(0.035)	(0.035)	—	(0.076)	(0.044)	(0.032)
Electric total	$ 0.032	$ 0.044	$ (0.012)	$ 0.046	$ 0.052	$ (0.006)
Firm natural gas	—	—	—	0.004	(0.005)	0.009
Total	$ 0.032	$ 0.044	$ (0.012)	$ 0.050	$ 0.047	$ 0.003

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

	Three Months Ended Sept. 30				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Actual					
Electric residential	0.4 %	0.3 %	(7.8)%	(2.0)%	(1.0)%
Electric C&I	2.1	3.4	4.4	1.9	3.1
Total retail electric sales	1.4	2.3	1.7	0.8	1.8
Firm natural gas sales	(2.0)	(0.8)	N/A	(7.8)	(2.0)

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	2.2 %	(0.3)%	(1.4)%	0.1 %	0.5 %
Electric C&I	1.8	3.1	5.3	2.2	3.2
Total retail electric sales	1.9	2.0	3.8	1.6	2.4
Firm natural gas sales	2.2	4.2	N/A	(4.6)	2.4

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	2.1 %	3.5 %	(2.1)%	1.7 %	2.0 %
Electric C&I	1.0	2.1	1.5	3.6	1.7
Total retail electric sales	1.4	2.5	0.8	3.0	1.8
Firm natural gas sales	6.9	(1.8)	N/A	(0.9)	3.7

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	2.6 %	0.9 %	0.4 %	0.4 %	1.4 %
Electric C&I	0.9	1.4	2.0	3.2	1.5
Total retail electric sales	1.5	1.2	1.7	2.4	1.5
Firm natural gas sales	2.4	(1.1)	N/A	(1.0)	1.0

	Nine Months Ended Sept. 30 (2020 Leap Year Adjusted)				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	3.0 %	1.2 %	0.7 %	0.8 %	1.8 %
Electric C&I	1.3	1.8	2.4	3.6	1.9
Total retail electric sales	1.9	1.6	2.0	2.7	1.9
Firm natural gas sales	3.2	(0.3)	N/A	(0.2)	1.8

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

Weather-adjusted sales results for each of our utility subsidiaries in 2021 reflect improving economies as the adverse effects of COVID-19 lessen. The recovery reflects increased sales in the C&I sector as businesses return to a more normal level. Residential sales remain elevated from pre-pandemic levels due to continuance of individuals working from home.

- PSCo — Residential sales rose based on a 1.2% increase in customers combined with higher use per customer. The growth in C&I sales was due to a 1.1% increase in customers and slightly higher use per customer, primarily in the services sector.
- NSP-Minnesota — Residential sales growth reflects a 1.2% increase in customers. The growth in C&I sales was due to a 0.9% increase in customers and slightly higher use per customer, primarily in the manufacturing sector.
- SPS — Residential sales rose based on a 0.8% increase in customers despite slightly lower use per customer. 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 0.8% increase in customer additions. The growth in C&I sales was due to a 1.1% increase in customers, primarily led by increases in the services sector.

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

- Natural gas sales primarily reflect a 1.2% increase in residential customers and a 0.6% increase in C&I customers, combined with slightly higher customer use.

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 generally 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 reduce electric revenue, margin and income taxes. See Note 5 for discussion of Winter Storm Uri.

Electric revenues and margin:

(Millions of Dollars)	Three Months Ended Sept. 30 2021	Three Months Ended Sept. 30 2020	Nine Months Ended Sept. 30 2021	Nine Months Ended Sept. 30 2020
Electric revenues	$ 3,176	$ 2,941	$ 8,643	$ 7,430
Electric fuel and purchased power	(1,210)	(981)	(3,643)	(2,611)
Electric margin	$ 1,966	$ 1,960	$ 5,000	$ 4,819

Changes in electric margin:

(Millions of Dollars)	Three Months Ended Sept. 30, 2021 vs. 2020	Nine Months Ended Sept. 30, 2021 vs. 2020
Non-fuel riders	$ 59	$ 196
Regulatory rate outcomes (Texas, New Mexico, Colorado, Wisconsin and North Dakota)	30	106
Proprietary commodity trading, net of sharing [a]	11	49
Sales and demand [b]	10	20
Estimated impact of weather (net of decoupling/sales true-up)	(8)	(3)
Texas 2019 rate case surcharge [c]	(70)	(70)
PTCs flowed back to customers (offset by lower ETR)	(31)	(111)
Other (net)	5	(6)
Total increase in electric margin	$ 6	$ 181

(a) Includes $27 million of net gains previously recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri. Additional amounts are primarily related to long-term physical generation contracts, which have increased in value as a result of higher energy prices.

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

(c) Impact to electric margin is due to the Texas rate case outcome, which was recognized in the third quarter of 2020 and was largely offset by recognition of previously deferred costs.

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

Natural gas revenues and margin:

(Millions of Dollars)	Three Months Ended Sept. 30 2021	Three Months Ended Sept. 30 2020	Nine Months Ended Sept. 30 2021	Nine Months Ended Sept. 30 2020
Natural gas revenues	$ 268	$ 219	$ 1,364	$ 1,082
Cost of natural gas sold and transported	(86)	(54)	(603)	(425)
Natural gas margin	$ 182	$ 165	$ 761	$ 657

Changes in natural gas margin:

(Millions of Dollars)	Three Months Ended Sept. 30, 2021 vs. 2020	Nine Months Ended Sept. 30, 2021 vs. 2020
Regulatory rate outcomes (Colorado)	$ 13	$ 84
Infrastructure and integrity riders	3	7
Estimated impact of weather	(1)	7
Other (net)	2	6
Total increase in natural gas margin	$ 17	$ 104

O&M Expenses — O&M expenses decreased $11 million, or 1.9%, for the third quarter and increased $44 million, or 2.6% year-to-date. Significant changes are summarized as follows:

(Millions of Dollars)	Three Months Ended Sept. 30, 2021 vs. 2020	Nine Months Ended Sept. 30, 2021 vs. 2020
Wind	$ 14	$ 36
Information technology and security	3	20
Distribution	9	16
Bad debt expense - PSCo settlement (See Note 4)	11	11
Natural gas systems	(4)	5
Texas rate case deferral (offset in electric margin)	(17)	(14)
Benefits	(24)	(31)
Other	(3)	1
Total (decrease) increase in O&M expenses	$ (11)	$ 44

The year-to-date increase was primarily due to expenses associated with new wind farms, software infrastructure and security costs, additional distribution expenses (vegetation management), bad debt expense related to the PSCo settlement and natural gas damage prevention. Increases were partially offset by recognition of previous deferrals for Texas rate case activity in 2020 (offset in electric margin) and a decrease in benefits expense (primarily related to long term incentives). Quarterly timing impacts also occurred throughout 2020 due to cost control initiatives to mitigate the adverse impact of COVID-19 on sales.

Depreciation and Amortization — Depreciation and amortization increased $24 million, or 4.7%, for the third quarter and $137 million, or 9.5% year-to-date. The increase was primarily driven by several wind farms going into service, normal system expansion and the implementation of new depreciation rates in various states. In addition, depreciation for the third quarter of 2020 reflected the recognition of previously deferred expenses associated with the Texas rate case.

Other (Expense) Income — Other (expense) income decreased $4 million for the third quarter and increased $11 million year-to-date. Changes were largely related to fluctuations in rabbi trust performance primarily offset in O&M expenses.

AFUDC, Equity and Debt — AFUDC decreased $13 million for the third quarter of 2021 and $53 million year-to-date. The decrease was primarily driven by completion of various wind projects.

Interest Charges — Interest charges decreased $10 million, or 4.5%, for the third quarter and were flat year-to-date. The quarter-to-date decrease was largely due to the timing of interest deferrals associated with the Texas rate case and lower interest rates, partially offset by higher debt levels primarily due to Winter Storm Uri.

***Earnings from Equity Method Investments* —** Earnings from equity method investments increased $1 million for the third quarter and $18 million year-to-date. The year-to-date increase was largely attributable to the performance of the EIP funds, which invest in energy technology companies.

Income Taxes — Effective income tax rate:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2021	2020	2021 vs 2020	2021	2020	2021 vs 2020
Federal statutory rate	21.0 %	21.0 %	— %	21.0 %	21.0 %	— %
State tax (net of federal tax effect)	5.0	5.0	—	5.0	5.1	(0.1)
(Decreases) increases:						
Wind PTCs [(a)]	(12.1)	(8.0)	(4.1)	(20.0)	(13.2)	(6.8)
Plant regulatory differences [(b)]	(5.8)	(7.2)	1.4	(6.0)	(7.4)	1.4
Net operating loss carryback	—	(1.9)	1.9	—	(1.0)	1.0
Other (net)	(1.5)	(2.2)	0.7	(1.3)	(2.5)	1.2
Effective income tax rate	6.6 %	6.7 %	(0.1)%	(1.3)%	2.0 %	(3.3)%

(a) Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

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

Income tax benefit increased $41 million year-to-date. The increase was primarily driven by an increase in wind PTCs due to additional wind facilities going into service. Impact of PTCs was partially offset by an increase in pretax earnings, lower plant regulatory differences, a carryback tax benefit in 2020 and lower non-plant accumulated deferred income tax amortization.

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

Xcel Energy's capital structure:

(Millions of Dollars)	Sept. 30, 2021	Percentage of Total Capitalization	Dec. 31, 2020	Percentage of Total Capitalization
Current portion of long-term debt	$ 621	2 %	$ 421	1 %
Short-term debt	1,747	5	584	2
Long-term debt	20,979	54	19,645	56
Total debt	23,347	61	20,650	59
Common equity	15,171	39	14,575	41
Total capitalization	$ 38,518	100 %	$ 35,225	100 %

Liquidity — As of Oct. 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	$ 427	$ 823	$ —	$ 823
PSCo	700	8	692	7	699
NSP-Minnesota	500	9	491	258	749
SPS	500	55	445	2	447
NSP-Wisconsin	150	—	150	3	153
Total	$ 3,100	$ 499	$ 2,601	$ 270	$ 2,871
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.

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 $41 million of outstanding letters of credits as of Sept. 30, 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 Oct. 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

Capital Expenditures — Base capital expenditures and incremental capital forecasts for Xcel Energy for 2022 through 2026 are as follows:

	Base Capital Forecast (Millions of Dollars)					
By Regulated Utility	**2022**	**2023**	**2024**	**2025**	**2026**	**2022 - 2026 Total**
PSCo	$ 1,930	$ 1,850	$ 2,070	$ 2,220	$ 1,860	$ 9,930
NSP-Minnesota	2,250	2,030	1,830	2,130	2,010	10,250
SPS	630	660	690	780	790	3,550
NSP-Wisconsin	480	420	540	460	390	2,290
Other [a]	(10)	—	10	(30)	10	(20)
Total base capital expenditures	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

	Base Capital Forecast (Millions of Dollars)					
By Function	**2022**	**2023**	**2024**	**2025**	**2026**	**2022 - 2026 Total**
Electric distribution	$ 1,485	$ 1,600	$ 1,520	$ 1,605	$ 1,720	$ 7,930
Electric transmission	1,105	1,220	1,575	1,965	1,555	7,420
Electric generation	645	580	670	650	650	3,195
Natural gas	655	670	695	660	660	3,340
Other	725	545	450	340	450	2,510
Renewables	665	345	230	340	25	1,605
Total base capital expenditures	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

[a] Other category includes intercompany transfers for safe harbor wind turbines.

The five-year capital forecast includes the proposed Colorado Pathway transmission expansion (approximately $1.7 billion), the proposed 460 MW Sherco solar facility (approximately $600 million) and the approved ALLETE wind repowering (approximately $210 million).

Additional capital investment in renewable generation and transmission may be needed in the five-year forecast pending approval of regulatory filings in Minnesota and Colorado. The approval of the proposed resource plans could result in up to 2,000 MW of renewable generation being needed between 2024 - 2026, resulting in potential capital expenditures estimated between $1.0 to $1.5 billion (assuming Xcel Energy were to own ~50% of the renewables). Additionally, the associated $0.5 billion to $1.0 billion of network upgrades, voltage support and interconnection work related to the Colorado Power Pathway could also be needed during this five-year forecast depending on resource mix, location and timing. Any additional capital investment would likely be funded with approximately 50% equity and 50% debt.

Xcel Energy's capital expenditure forecast is subject to continuing review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, safety and reliability needs, regulatory decisions, legislative initiatives (e.g., federal clean energy and tax policy), reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental initiatives and regulation, and merger, acquisition and divestiture opportunities.

Financing for Capital Expenditures through 2026 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Current estimated financing plans of Xcel Energy for 2022 through 2026:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [a]	$ 17,640
New debt [b]	7,110
Equity through the DRIP and benefit program	450
Other equity	800
Base capital expenditures 2022-2026	$ 26,000
Maturing Debt	$ 3,900

[a] Net of dividends and pension funding.

[b] Reflects a combination of short and long-term debt; net of refinancing.

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 may issue $800 million in equity under an at-the-market program. Xcel Energy Inc. and its utility subsidiaries issued or plan to issue the following:

Issuer	Security	Amount	Status	Tenor	Coupon
Xcel Energy	Unsecured Bonds	$ 800	2021 Q4	5 Year/10 Year	TBD
PSCo	First Mortgage Bonds	750	Completed	10 Year	1.88
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	100	Completed	30 Year	2.82

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 and Regulation

NSP-Minnesota — 2022 Minnesota Electric Rate Case — On Oct. 25, 2021, NSP-Minnesota filed a three-year electric rate case with the Minnesota Public Utilities Commission (MPUC). The request is driven by ongoing investments in carbon free electrical generation, distribution and transmission infrastructure. The rate case is based on a requested ROE of 10.2% and a 52.50% equity ratio.

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 addition, NSP-Minnesota requested interim rates, subject to refund, of $288 million to be implemented in January 2022 and an incremental $135 million to be implemented in January 2023. To mitigate the interim increase, NSP-Minnesota also proposed to continue a sales true-up for all customer classes in both 2022 and 2023. This would result in interim rates, subject to refund, of $190 million to be implemented in January 2022 and an incremental $116 million to be implemented in January 2023. A final MPUC decision on the rate case is anticipated in the second quarter of 2023.

NSP-Minnesota — 2022 Minnesota Natural Gas Rate Case — NSP-Minnesota plans to file a request with the MPUC for an annual natural gas rate case in November 2021. As part of the request, NSP-Minnesota plans to file an option for a one-year stay-out alternative.

NSP-Minnesota — 2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a rate case with the North Dakota Public Service Commission (NDPSC) seeking a rate increase of $19 million based on a ROE of 10.2%, an equity ratio of 52.5% and rate base of $677 million. In August 2021, the NDPSC approved a settlement between NSP-Minnesota and various parties, which includes the following, effective Jan. 1, 2021:

- Base revenue increase of $7 million.
- ROE of 9.5%.
- Equity ratio of 52.5%.
- Deferral of advanced grid intelligence and security (AGIS) initiative capital and O&M expenses.
- An earnings cap mechanism, which would return to customers 100% of earnings equal to or in excess of 9.75% ROE, effective until the next rate case.

NSP-Minnesota — 2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSC for a natural gas rate increase of $7 million, or 10.49%. The filing based on a requested ROE of 10.5%, an equity ratio of 52.54%, a 2022 forecast test year and a rate base of approximately $140 million. NSP-Minnesota requested interim rates, subject to refund, of $7 million to be implemented on Nov. 1, 2021.

NSP-Wisconsin — Wisconsin Electric and Natural Gas Settlement — In July 2021, NSP-Wisconsin filed with the PSCW seeking approval of a rate case settlement with various intervenors for 2022-2023. If approved, the settlement agreement would increase electric rates by $35 million (4.9%) for 2022 and an incremental $18 million increase (2.5%) for 2023. For the natural gas utility, rates would increase by $10 million (8.4%) for 2022 and an incremental $3 million (2.3%) for 2023.

Key elements of the settlement:

- ROE of 9.80% for 2022 and 10.00% for 2023.
- Equity ratio of 52.5% for both 2022 and 2023.
- Returning $9 million in various net regulatory liabilities to offset customer impacts in 2023.
- Deferring certain pension and other post-employment benefit expense in 2021 through 2023.
- Addressing COVID-19 deferral recovery in the next rate case proceeding.
- Deferring potential changes in tax expenses due to changes in federal or state tax law in 2021 through 2023.
- Incorporating an earnings sharing mechanism for 2022 and 2023.

A PSCW decision is anticipated in the fourth quarter of 2021.

NSP-Wisconsin — Michigan Electric Rate Case — In September 2021, NSPW filed a Michigan electric rate case seeking a rate increase of $2.5 million, based on a ROE of 10.2% and an equity ratio of 52.5%.

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 is 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. A historical test year was filed with a revenue deficiency of $404 million, including a 10.5% ROE. Rates are expected to be effective April 9, 2022.

PSCo — Settlement — Subsequent Event — On Oct. 25, 2021, PSCo filed a comprehensive settlement with the CPUC Staff and the Colorado Energy Office, which proposes to address four outstanding regulatory items including recovery of fuel costs related to Winter Storm Uri, disputed revenue associated with the 2020 electric decoupling pilot program year, replacement power costs associated with an extended outage at Comanche Unit 3 during 2020 and deferred customer bad debt balances associated with COVID-19. The Colorado Office of the Utility Consumer Advocate has not signed the settlement. A hearing and a CPUC decision on the settlement is expected in the first quarter of 2022.

Key terms of the proposed settlement:

- PSCo would fully recover Winter Storm Uri deferred net natural gas, fuel and purchased energy 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 through a rider mechanism. Recovery would commence Jan. 1, 2022 for electric costs and April 1, 2022 for natural gas costs.
- PSCo will refund electric customers $41 million (previously deferred) related to the 2020 electric decoupling pilot program.
- PSCo agreed to forego recovery of $14 million due to an extended outage at Comanche Unit 3 being offline during 2020.
- PSCo agreed to not seek recovery of COVID-19 related bad debt expense, previously deferred as a regulatory asset, and recorded an additional $11 million of incremental bad debt expense for the period ended Sept. 30, 2021.

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 approximately $84 million.

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

In June 2021, SPS and various parties filed an uncontested comprehensive stipulation, which includes:

- Base rate revenue increase of $62 million.
- ROE of 9.35% for purposes of filings related to (1) the Hale and Sagamore wind projects; and (2) reconciliation of the settlement revenue requirement.
- Equity ratio of 54.72%.
- Increase in depreciation expense of $6 million. This includes a change in the depreciable lives of the Tolk power plant to 2032 and coal handling assets at the Harrington facility to 2024.

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. The current request is seeking an increase in base rates of approximately $140 million. SPS' net rate increase to Texas customers is expected to be approximately $71 million, or 9.2%, as a result of the offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is 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-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 coal handling assets at the Harrington facility (to 2024).

In October 2021, the scheduled hearings were abated to continue progress on a potential rate case settlement between SPS and various intervenors.

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 February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. 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. As a result of the extremely high market prices, Xcel Energy incurred net natural gas, fuel and purchased energy costs of approximately $985 million (largely deferred as regulatory assets) in the first quarter.

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 cost increases for future recovery and are proposing to recover the cost increases over a period of up to 30 months to mitigate the impact to customer bills. Additionally, we are not requesting recovery of financing costs in order to further limit the impact to our customers.

Proceedings initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	NSP-Minnesota filed with the MPUC seeking recovery of $215 million in incremental costs from natural gas customers. The Department of Commerce (DOC) recommended disallowances of $21 million related to the utilization of natural gas storage. The Office of the Attorney General (OAG) recommended disallowances of $34 million based on: (1) utilization of natural gas storage; (2) failure to enter fixed-price contracts; (3) failure to maximize curtailments to interruptible customers; and (4) inadequate conservation efforts to reduce demand. In addition, intervenors raised questions regarding peaking plant availability. In August 2021, the MPUC allowed the utilities to start recovery of all Uri storm costs starting in September 2021 over 27 months (no financing charge). The cost recovery will be subject to refund pending the outcome of a contested case before an ALJ that will consider the DOC/OAG recommendations and issues related to the peaking plants. A decision is expected in the summer of 2022.
	South Dakota	Winter Storm Uri had no impact on South Dakota electric costs as NSP-Minnesota was a net seller in the electric market.
	North Dakota	In June, the NDPSC approved recovery of $32 million in natural gas costs over 15 months (starting July 2021) with no financing charge.
NSP-Wisconsin	Wisconsin	In March, the PSCW approved NSP-Wisconsin's proposal to recover $45 million of Uri natural gas costs over nine months through December 2021 with no financing charge.
	Michigan	In May, the Michigan Public Service Commission approved recovery of $2 million in natural gas costs over 10 months with no financing charge.

Utility Subsidiary	Jurisdiction	Regulatory Status
PSCo	Colorado	In May, 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. In September, intervenors filed testimony. The CPUC Staff recommended disallowances of approximately $99 million (electric) and $105 million (natural gas). Additionally, they proposed to net approximately $50 million of regulatory liabilities (decoupling related) from electric costs. The UCA recommended disallowances of approximately $131 million. The COEO recommended disallowances of approximately $46 million for not utilizing demand response programs during the event. In October, a partial settlement was reached with the CPUC Staff and the COEO. See Subsequent Event in Note 4. A decision is expected in the first quarter of 2022. In addition, the CPUC is considering prospective changes in fuel cost recovery.
SPS	Texas	As part of the Texas fuel surcharge filing, SPS filed for recovery of $76 million, over 24 months, in under-collected purchased power and fuel costs through March 2021, subject to revision due to re-settlements. Of this amount, $62 million was attributed to Winter Storm Uri. In the third quarter, SPS filed a supplemental application and testimony to recover an additional $26 million in under-collected purchased power and fuel costs through June 2021 resulting primarily from Southwest Power Pool resettlements and continued increases in natural gas prices. The proposed recovery remains over 24 months beginning in February 2022. In October 2021, intervenors proposed a $10 million disallowance of Winter Storm Uri off-system sales margin in addition to recommending an extended recovery period. A public hearing is scheduled to begin on Nov. 1, 2021, with a final PUCT decision expected in early 2022
	New Mexico	The NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

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

Xcel Energy 2021 Earnings Guidance — Xcel Energy narrows 2021 GAAP and ongoing earnings guidance to $2.94 to $2.98 from $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 ~1.5 to 2%.
- Weather-normalized retail firm natural gas sales are projected to increase ~1 to 2%.
- 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 increase ~1%.
- Depreciation expense is projected to increase approximately $170 million to $180 million.
- Property taxes are projected to increase approximately $25 million to $35 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 (4%) to (5%). The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not have a material impact on net income.

***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 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 $30 million to $40 million (net of PTCs). PTCs are credited to customers, through capital riders and reductions to electric margin.
- O&M expenses are projected to increase approximately 1%.
- Depreciation expense is projected to increase approximately $260 million to $270 million.
- Property taxes are projected to increase approximately $35 million to $45 million.
- Interest expense (net of AFUDC - debt) is projected to increase $45 million to $55 million.
- AFUDC - equity is projected to be relatively flat.
- ETR is projected to be ~(5%) to (6%). 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 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 Sept. 30	
	2021	2020
Operating revenues:		
Electric and natural gas	$ 3,444	$ 3,160
Other	23	22
Total operating revenues	3,467	3,182
Net income	$ 609	$ 603
Weighted average diluted common shares outstanding	539	528
Components of EPS — Diluted		
Regulated utility	$ 1.19	$ 1.21
Xcel Energy Inc. and other costs	(0.06)	(0.07)
GAAP and ongoing diluted EPS [a][b]	**$ 1.13**	**$ 1.14**
Book value per share	$ 28.12	$ 26.10
Cash dividends declared per common share	0.4575	0.43

	Nine Months Ended Sept. 30	
	2021	2020
Operating revenues:		
Electric and natural gas	$ 10,007	$ 8,512
Other	69	67
Total operating revenues	10,076	8,579
Net income	$ 1,282	$ 1,185
Weighted average diluted common shares outstanding	539	527
Components of EPS — Diluted		
Regulated utility	$ 2.54	$ 2.42
Xcel Energy Inc. and other costs	(0.16)	(0.17)
GAAP and ongoing diluted EPS [a]	**2.38**	**2.25**
Book value per share	$ 28.14	$ 26.15
Cash dividends declared per common share	1.373	1.29

[a] For the three and nine months ended Sept. 30, 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.