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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**

# FORM 10-Q

**(Mark One)**

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended Sept. 30, 2021**

**or**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to**

**Commission File Number: 001-3034**

## Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Minnesota** | **41-0448030** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **414 Nicollet Mall Minneapolis Minnesota** | **55401** |
| (Address of principal executive offices) | (Zip Code) |

**(612) 330-5500**
(Registrant's telephone number, including area code)

**N/A**
(Former name, former address and former fiscal year, if changed since last report)

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|
| Common Stock, $2.50 par value | XEL | Nasdaq Stock Market LLC |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer ☒ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Smaller reporting company ☐ |
| | Emerging growth company ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

| Class | Outstanding at Oct. 26, 2021 |
|---|---|
| Common Stock, $2.50 par value | 538,675,570 shares |

TABLE OF CONTENTS



This Form 10-Q is filed by Xcel Energy Inc. Additional information is available on various filings with the Securities and Exchange Commission.

## Definitions of Abbreviations

***Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)***

| | |
|---|---|
| e prime | e prime inc. |
| NSP-Minnesota | Northern States Power Company, a Minnesota corporation |
| NSP-Wisconsin | Northern States Power Company, a Wisconsin corporation |
| PSCo | Public Service Company of Colorado |
| SPS | Southwestern Public Service Company |
| Utility subsidiaries | NSP-Minnesota, NSP-Wisconsin, PSCo and SPS |
| WYCO | WYCO Development, LLC |
| Xcel Energy | Xcel Energy Inc. and its subsidiaries |

***Federal and State Regulatory Agencies***

| | |
|---|---|
| COEO | Colorado Energy Office |
| CPUC | Colorado Public Utilities Commission |
| D.C. Circuit | United States Court of Appeals for the District of Columbia Circuit |
| DOC | Minnesota Department of Commerce |
| EPA | United States Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| MPUC | Minnesota Public Utilities Commission |
| NDPSC | North Dakota Public Service Commission |
| NMPRC | New Mexico Public Regulation Commission |
| NRC | Nuclear Regulatory Commission |
| OAG | Minnesota Office of Attorney General |
| PSCW | Public Service Commission of Wisconsin |
| PUCT | Public Utility Commission of Texas |
| SEC | Securities and Exchange Commission |
| UCA | Colorado Office of the Utility Consumer Advocate |

***Electric, Purchased Gas and Resource Adjustment Clauses***

| | |
|---|---|
| DSM | Demand side management |
| FCA | Fuel clause adjustment |
| GUIC | Gas utility infrastructure cost rider |
| PSIA | Pipeline System Integrity Adjustment |
| RES | Renewable energy standard |
| TCR | Transmission cost recovery adjustment |

***Other***

| | |
|---|---|
| AFUDC | Allowance for funds used during construction |
| ALJ | Administrative Law Judge |
| ASC | FASB Accounting Standards Codification |
| C&I | Commercial and Industrial |
| CCR | Coal combustion residuals |
| CCR Rule | Final rule (40 CFR 257.50 - 257.107) published by EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste |
| CDD | Cooling degree-days |
| CEO | Chief executive officer |
| CFO | Chief financial officer |
| COVID-19 | Novel coronavirus |
| DRIP | Dividend Reinvestment and Stock Purchase Program |
| EIP | Energy Impact Partners |
| EPS | Earnings per share |
| ETR | Effective tax rate |
| FASB | Financial Accounting Standards Board |
| FTR | Financial transmission right |
| GAAP | United States generally accepted accounting principles |
| GCA | Gas cost adjustment |
| GE | General Electric Company |
| HDD | Heating degree-days |
| IPP | Independent power producing entity |
| KEPCO | Korea Electric Power Corporation |
| LLC | Limited liability company |
| LP&L | Lubbock Power and Light |
| MDL | Multi district litigation |
| MEC | Mankato Energy Center |
| MGP | Manufactured gas plant |
| MISO | Midcontinent Independent System Operator, Inc. |
| NAV | Net asset value |
| NOL | Net operating loss |
| NOPR | Notice of Proposed Rulemaking |
| O&M | Operating and maintenance |
| OATT | Open Access Transmission Tariff |
| PFAS | Per- and PolyFluoroAlkyl Substances |
| PPA | Power purchase agreement |
| PTC | Production tax credit |
| ROE | Return on equity |
| RTO | Regional Transmission Organization |
| SMMPA | Southern Minnesota Municipal Power Agency |
| SPP | Southwest Power Pool, Inc. |
| THI | Temperature-humidity index |
| TOs | Transmission owners |
| VaR | Value at Risk |
| VIE | Variable interest entity |

***Measurements***

| | |
|---|---|
| MW | Megawatts |

## Forward-Looking Statements

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 filing with the SEC 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.

## PART I — FINANCIAL INFORMATION

## ITEM 1 — FINANCIAL STATEMENTS

### 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 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)**
*(amounts in millions)*

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| **Net income** | $ 609 | $ 603 | $ 1,282 | $ 1,185 |
| **Other comprehensive income (loss)** | | | | |
| Pension and retiree medical benefits: | | | | |
| Reclassifications of loss to net income, net of tax of $1, $—, $2 and $1, respectively | 4 | 1 | 5 | 4 |
| Derivative instruments: | | | | |
| Net fair value increase (decrease), net of tax of $1, $—, $1 and $(3), respectively | 3 | — | 4 | (10) |
| Reclassification of losses to net income, net of tax of $—, $—, $1 and $1, respectively | 2 | 1 | 6 | 4 |
| Total other comprehensive income (loss) | 9 | 2 | 15 | (2) |
| **Total comprehensive income** | $ 618 | $ 605 | $ 1,297 | $ 1,183 |

See Notes to Consolidated Financial Statements

## XCEL ENERGY INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
*(amounts in millions)*

| | Nine Months Ended Sept. 30 | |
|---|---|---|
| | 2021 | 2020 |
| **Operating activities** | | |
| Net income | $ 1,282 | $ 1,185 |
| Adjustments to reconcile net income to cash provided by operating activities: | | |
| Depreciation and amortization | 1,597 | 1,459 |
| Nuclear fuel amortization | 86 | 94 |
| Deferred income taxes | (9) | 45 |
| Allowance for equity funds used during construction | (53) | (91) |
| Earnings from equity method investments | (47) | (29) |
| Dividends from equity method investments | 31 | 32 |
| Provision for bad debts | 53 | 39 |
| Share-based compensation expense | 20 | 60 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (152) | (108) |
| Accrued unbilled revenues | 58 | 124 |
| Inventories | (82) | (37) |
| Other current assets | 8 | (68) |
| Accounts payable | 61 | (97) |
| Net regulatory assets and liabilities | (997) | (139) |
| Other current liabilities | (22) | (54) |
| Pension and other employee benefit obligations | (131) | (138) |
| Other, net | (124) | (103) |
| Net cash provided by operating activities | 1,579 | 2,174 |
| | | |
| **Investing activities** | | |
| Capital/construction expenditures | (3,032) | (3,681) |
| Sale of MEC | — | 684 |
| Purchase of investment securities | (540) | (1,275) |
| Proceeds from the sale of investment securities | 531 | 1,260 |
| Other, net | (24) | (9) |
| Net cash used in investing activities | (3,065) | (3,021) |
| | | |
| **Financing activities** | | |
| Proceeds from (repayments of) short-term borrowings, net | 1,163 | (95) |
| Proceeds from issuances of long-term debt | 1,920 | 2,940 |
| Repayments of long-term debt, including reacquisition premiums | (399) | (701) |
| Proceeds from issuance of common stock | 13 | 5 |
| Dividends paid | (698) | (638) |
| Other, net | (11) | (27) |
| Net cash provided by financing activities | 1,988 | 1,484 |
| | | |
| Net change in cash, cash equivalents and restricted cash | 502 | 637 |
| Cash, cash equivalents and restricted cash at beginning of period | 129 | 248 |
| Cash, cash equivalents and restricted cash at end of period | $ 631 | $ 885 |
| | | |
| Supplemental disclosure of cash flow information: | | |
| Cash paid for interest (net of amounts capitalized) | $ (592) | $ (582) |
| Cash paid for income taxes, net | (6) | (17) |
| | | |
| Supplemental disclosure of non-cash investing and financing transactions: | | |
| Accrued property, plant and equipment additions | $ 476 | $ 933 |
| Inventory transfers to property, plant and equipment | 87 | 250 |
| Operating lease right-of-use assets | 4 | 361 |
| Allowance for equity funds used during construction | 53 | 91 |
| Issuance of common stock for reinvested dividends and/or equity awards | 26 | 51 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (UNAUDITED)**
*(amounts in millions, except share and per share data)*

| | Sept. 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | $ 631 | $ 129 |
| Accounts receivable, net | 1,022 | 916 |
| Accrued unbilled revenues | 656 | 714 |
| Inventories | 587 | 535 |
| Regulatory assets | 1,073 | 640 |
| Derivative instruments | 228 | 49 |
| Prepaid taxes | 55 | 42 |
| Prepayments and other | 235 | 250 |
| Total current assets | 4,487 | 3,275 |
| Property, plant and equipment, net | 44,730 | 42,950 |
| Other assets | | |
| Nuclear decommissioning fund and other investments | 3,446 | 3,096 |
| Regulatory assets | 3,101 | 2,737 |
| Derivative instruments | 72 | 30 |
| Operating lease right-of-use assets | 1,342 | 1,490 |
| Other | 339 | 379 |
| Total other assets | 8,300 | 7,732 |
| Total assets | $ 57,517 | $ 53,957 |
| **Liabilities and Equity** | | |
| Current liabilities | | |
| Current portion of long-term debt | $ 621 | $ 421 |
| Short-term debt | 1,747 | 584 |
| Accounts payable | 1,319 | 1,237 |
| Regulatory liabilities | 338 | 311 |
| Taxes accrued | 553 | 578 |
| Accrued interest | 206 | 203 |
| Dividends payable | 246 | 231 |
| Derivative instruments | 76 | 53 |
| Operating lease liabilities | 218 | 214 |
| Other | 440 | 407 |
| Total current liabilities | 5,764 | 4,239 |
| Deferred credits and other liabilities | | |
| Deferred income taxes | 4,913 | 4,746 |
| Regulatory liabilities | 5,389 | 5,302 |
| Asset retirement obligations | 3,094 | 2,884 |
| Derivative instruments | 99 | 131 |
| Customer advances | 199 | 197 |
| Pension and employee benefit obligations | 515 | 666 |
| Operating lease liabilities | 1,187 | 1,344 |
| Other | 207 | 228 |
| Total deferred credits and other liabilities | 15,603 | 15,498 |
| Commitments and contingencies | | |
| Capitalization | | |
| Long-term debt | 20,979 | 19,645 |
| Common stock — 1,000,000,000 shares authorized of $2.50 par value; 538,458,952 and 537,438,394 shares outstanding at Sept. 30, 2021 and Dec. 31, 2020, respectively | 1,346 | 1,344 |
| Additional paid in capital | 7,443 | 7,404 |
| Retained earnings | 6,508 | 5,968 |
| Accumulated other comprehensive loss | (126) | (141) |
| Total common stockholders' equity | 15,171 | 14,575 |
| Total liabilities and equity | $ 57,517 | $ 53,957 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)**
*(amounts in millions, except per share data; shares in actual amounts)*

| | Common Stock Issued | | | | | |
|---|---|---|---|---|---|---|
| | Shares | Par Value | Additional Paid In Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total Common Stockholders' Equity |
| **Three Months Ended Sept. 30, 2021 and 2020** | | | | | | |
| **Balance at June 30, 2020** | 525,204,978 | $ 1,313 | $ 6,679 | $ 5,538 | $ (145) | $ 13,385 |
| Net income | | | | 603 | | 603 |
| Other comprehensive income | | | | | 2 | 2 |
| Dividends declared on common stock ($0.43 per share) | | | | (226) | | (226) |
| Issuances of common stock | 302,321 | 1 | 9 | | | 10 |
| Repurchase of common stock | (54,475) | — | (4) | | | (4) |
| Share-based compensation | | | 10 | (3) | | 7 |
| **Balance at Sept. 30, 2020** | 525,452,824 | $ 1,314 | $ 6,694 | $ 5,912 | $ (143) | $ 13,777 |
| | | | | | | |
| **Balance at June 30, 2021** | 538,305,927 | $ 1,346 | $ 7,435 | $ 6,146 | $ (135) | $ 14,792 |
| Net income | | | | 609 | | 609 |
| Other comprehensive income | | | | | 9 | 9 |
| Dividends declared on common stock ($0.4575 per share) | | | | (247) | | (247) |
| Issuances of common stock | 153,025 | — | 10 | | | 10 |
| Share-based compensation | | | (2) | — | | (2) |
| **Balance at Sept. 30, 2021** | 538,458,952 | $ 1,346 | $ 7,443 | $ 6,508 | $ (126) | $ 15,171 |

| | Common Stock Issued | | | | | |
|---|---|---|---|---|---|---|
| | Shares | Par Value | Additional Paid In Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total Common Stockholders' Equity |
| **Nine Months Ended Sept. 30, 2021 and 2020** | | | | | | |
| **Balance at Dec. 31, 2019** | 524,539,000 | $ 1,311 | $ 6,656 | $ 5,413 | $ (141) | $ 13,239 |
| Net income | | | | 1,185 | | 1,185 |
| Other comprehensive loss | | | | | (2) | (2) |
| Dividends declared on common stock ($1.29 per share) | | | | (679) | | (679) |
| Issuances of common stock | 968,299 | 3 | 30 | | | 33 |
| Repurchase of common stock | (54,475) | — | (4) | | | (4) |
| Share-based compensation | | | 12 | (5) | | 7 |
| Adoption of ASC Topic 326 | | | | (2) | | (2) |
| **Balance at Sept. 30, 2020** | 525,452,824 | $ 1,314 | $ 6,694 | $ 5,912 | $ (143) | $ 13,777 |
| | | | | | | |
| **Balance at Dec. 31, 2020** | 537,438,394 | $ 1,344 | $ 7,404 | $ 5,968 | $ (141) | $ 14,575 |
| Net income | | | | 1,282 | | 1,282 |
| Other comprehensive income | | | | | 15 | 15 |
| Dividends declared on common stock ($1.373 per share) | | | | (739) | | (739) |
| Issuances of common stock | 1,020,558 | 2 | 38 | | | 40 |
| Share-based compensation | | | 1 | (3) | | (2) |
| **Balance at Sept. 30, 2021** | 538,458,952 | $ 1,346 | $ 7,443 | $ 6,508 | $ (126) | $ 15,171 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**Notes to Consolidated Financial Statements (UNAUDITED)**

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 2021 and Dec. 31, 2020; the results of Xcel Energy's operations, including the components of net income, comprehensive income, and changes in stockholders' equity for the three and nine months ended Sept. 30, 2021 and 2020; and Xcel Energy's cash flows for the nine months ended Sept. 30, 2021 and 2020.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2021, up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2020 balance sheet information has been derived from the audited 2020 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2020.

Notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2020, filed with the SEC on Feb. 17, 2021.

Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

## 1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2020 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

### Subsequent Event

On Oct. 25, 2021, PSCo filed a comprehensive settlement with the CPUC Staff and the COEO, 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 UCA 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 for replacement power costs due to an extended outage at Comanche Unit 3 during 2020.
- PSCo also 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.

## 2. Accounting Pronouncements

***Credit Losses*** — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

Xcel Energy implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $2 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for bad debts on accrued unbilled revenues, the Jan. 1, 2020, adoption of ASC Topic 326 did not have a significant impact on Xcel Energy's consolidated financial statements.

## 3. Selected Balance Sheet Data

| (Millions of Dollars) | Sept. 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| **Accounts receivable, net** | | |
| Accounts receivable | $ 1,119 | $ 995 |
| Less allowance for bad debts | (97) | (79) |
| Accounts receivable, net | $ 1,022 | $ 916 |

| (Millions of Dollars) | Sept. 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| **Inventories** | | |
| Materials and supplies | $ 283 | $ 275 |
| Fuel | 155 | 176 |
| Natural gas | 149 | 84 |
| Total inventories | $ 587 | $ 535 |

| (Millions of Dollars) | Sept. 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| **Property, plant and equipment, net** | | |
| Electric plant | $ 49,293 | $ 47,104 |
| Natural gas plant | 7,443 | 7,135 |
| Common and other property | 2,519 | 2,503 |
| Plant to be retired [(a)] | 603 | 677 |
| Construction work in progress | 2,263 | 1,877 |
| Total property, plant and equipment | 62,121 | 59,296 |
| Less accumulated depreciation | (17,711) | (16,657) |
| Nuclear fuel | 3,065 | 2,970 |
| Less accumulated amortization | (2,745) | (2,659) |
| Property, plant and equipment, net | $ 44,730 | $ 42,950 |

(a) Includes regulator-approved retirements of Comanche Units 1 and 2 and jointly owned Craig Unit 1 for PSCo and Sherco Units 1 and 2 for NSP-Minnesota. Also includes SPS' expected retirement of Tolk and conversion of Harrington to natural gas, and PSCo's planned retirement of jointly owned Craig Unit 2.

## 4. Borrowings and Other Financing Instruments

### Short-Term Borrowings

***Short-Term Debt*** — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities and term loan agreements.

Commercial paper and term loan borrowings outstanding for Xcel Energy:

| (Amounts in Millions, Except Interest Rates) | Three Months Ended Sept. 30, 2021 | Year Ended Dec. 31, 2020 |
|---|---|---|
| Borrowing limit | $ 4,300 | $ 3,100 |
| Amount outstanding at period end | 1,747 | 584 |
| Average amount outstanding | 1,742 | 1,126 |
| Maximum amount outstanding | 1,857 | 2,080 |
| Weighted average interest rate, computed on a daily basis | 0.57 % | 1.45 % |
| Weighted average interest rate at period end | 0.56 | 0.23 |

***Letters of Credit*** — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. There were $19 million and $20 million of letters of credit outstanding under the credit facilities at Sept. 30, 2021 and Dec. 31, 2020, respectively. Amounts approximate their fair value and are subject to fees.

***Revolving Credit Facilities*** — In order to issue commercial paper, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities at least equal to the amount of commercial paper borrowing limits and cannot issue commercial paper exceeding available credit facility capacity. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

As of Sept. 30, 2021, Xcel Energy Inc. and its utility subsidiaries had the following committed revolving credit facilities available:

| (Millions of Dollars) | Credit Facility [a] | Drawn [b] | Available |
|---|---|---|---|
| Xcel Energy Inc. | $ 1,250 | $ 529 | $ 721 |
| PSCo | 700 | 8 | 692 |
| NSP-Minnesota | 500 | 9 | 491 |
| SPS | 500 | 20 | 480 |
| NSP-Wisconsin | 150 | — | 150 |
| Total | $ 3,100 | $ 566 | $ 2,534 |

[a] Expires in June 2024.
[b] Includes outstanding commercial paper and letters of credit.

Xcel Energy Inc., NSP-Minnesota, PSCo, and SPS each have the right to request an extension of the credit facility termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available credit facilities capacity. Xcel Energy Inc. and its utility subsidiaries had no direct advances on the credit facilities outstanding as of Sept. 30, 2021 and Dec. 31, 2020.

***Term Loan Agreements*** — In February 2021, Xcel Energy Inc. entered into a $1.2 billion 364-Day Term Loan Agreement that matures Feb. 17, 2022. Xcel Energy has an option to extend through Feb. 16, 2023. The term loan includes one financial covenant, requiring Xcel Energy's consolidated funded debt to total capitalization ratio to be less than or equal to 65%.

As of Sept. 30, 2021, Xcel Energy Inc.'s term loan borrowings were as follows:

| (Millions of Dollars) | Limit | Amount Used | Available |
|---|---|---|---|
| Xcel Energy Inc. | $ 1,200 | $ 1,200 | $ — |

**Bilateral Credit Agreement**

In April 2021, NSP-Minnesota's uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Sept. 30, 2021, NSP-Minnesota's outstanding letters of credit under the bilateral credit agreement were as follows:

| (Millions of Dollars) | Limit | Amount Outstanding | Available |
|---|---|---|---|
| NSP-Minnesota | $ 75 | $ 41 | $ 34 |

**Long-Term Borrowings and Other Financing Instruments**

During the nine months ended Sept. 30, 2021, Xcel Energy Inc. and its utility subsidiaries issued the following:

- PSCo issued $750 million of 1.875% first mortgage bonds due June 15, 2031.
- SPS issued $250 million of 3.15% first mortgage bonds due May 1, 2050.
- NSP-Minnesota issued $425 million of 2.25% first mortgage bonds due April 1, 2031 and $425 million of 3.20% first mortgage bonds due April 1, 2052.
- NSP-Wisconsin issued $100 million of 2.82% first mortgage bonds due May 1, 2051.

***Other Equity*** — Xcel Energy Inc. issued $38 million and $30 million of equity through the DRIP during the nine months ended Sept. 30, 2021 and 2020, respectively. The program allows shareholders to reinvest their dividends directly in Xcel Energy Inc. common stock.

## 5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues consisted of the following:

| | Three Months Ended Sept. 30, 2021 | | | |
|---|---|---|---|---|
| (Millions of Dollars) | Electric | Natural Gas | All Other | Total |
| **Major revenue types** | | | | |
| Revenue from contracts with customers: | | | | |
| Residential | $ 999 | $ 133 | $ 12 | $ 1,144 |
| C&I | 1,515 | 76 | 7 | 1,598 |
| Other | 35 | — | 1 | 36 |
| **Total retail** | 2,549 | 209 | 20 | 2,778 |
| Wholesale | 288 | — | — | 288 |
| Transmission | 167 | — | — | 167 |
| Other | 17 | 45 | — | 62 |
| **Total revenue from contracts with customers** | 3,021 | 254 | 20 | 3,295 |
| Alternative revenue and other | 155 | 14 | 3 | 172 |
| **Total revenues** | $ 3,176 | $ 268 | $ 23 | $ 3,467 |

| (Millions of Dollars) | Three Months Ended Sept. 30, 2020 Electric | Natural Gas | All Other | Total |
|---|---|---|---|---|
| **Major revenue types** | | | | |
| Revenue from contracts with customers: | | | | |
| Residential | $ 962 | $ 124 | $ 11 | $ 1,097 |
| C&I | 1,340 | 56 | 5 | 1,401 |
| Other | 34 | — | 2 | 36 |
| **Total retail** | 2,336 | 180 | 18 | 2,534 |
| Wholesale | 227 | — | — | 227 |
| Transmission | 157 | — | — | 157 |
| Other | 17 | 28 | — | 45 |
| **Total revenue from contracts with customers** | 2,737 | 208 | 18 | 2,963 |
| Alternative revenue and other | 204 | 11 | 4 | 219 |
| **Total revenues** | $ 2,941 | $ 219 | $ 22 | $ 3,182 |

| (Millions of Dollars) | Nine Months Ended Sept. 30, 2021 Electric | Natural Gas | All Other | Total |
|---|---|---|---|---|
| **Major revenue types** | | | | |
| Revenue from contracts with customers: | | | | |
| Residential | $ 2,488 | $ 774 | $ 33 | $ 3,295 |
| C&I | 3,830 | 389 | 22 | 4,241 |
| Other | 96 | — | 5 | 101 |
| **Total retail** | 6,414 | 1,163 | 60 | 7,637 |
| Wholesale | 1,265 | — | — | 1,265 |
| Transmission | 461 | — | — | 461 |
| Other | 51 | 106 | — | 157 |
| **Total revenue from contracts with customers** | 8,191 | 1,269 | 60 | 9,520 |
| Alternative revenue and other | 452 | 95 | 9 | 556 |
| **Total revenues** | $ 8,643 | $ 1,364 | $ 69 | $ 10,076 |

| (Millions of Dollars) | Nine Months Ended Sept. 30, 2020 Electric | Natural Gas | All Other | Total |
|---|---|---|---|---|
| **Major revenue types** | | | | |
| Revenue from contracts with customers: | | | | |
| Residential | $ 2,356 | $ 647 | $ 32 | $ 3,035 |
| C&I | 3,481 | 308 | 20 | 3,809 |
| Other | 94 | — | 4 | 98 |
| **Total retail** | 5,931 | 955 | 56 | 6,942 |
| Wholesale | 553 | — | — | 553 |
| Transmission | 442 | — | — | 442 |
| Other | 55 | 86 | — | 141 |
| **Total revenue from contracts with customers** | 6,981 | 1,041 | 56 | 8,078 |
| Alternative revenue and other | 449 | 41 | 11 | 501 |
| **Total revenues** | $ 7,430 | $ 1,082 | $ 67 | $ 8,579 |

## 6. Income Taxes

Note 7 to the consolidated financial statements included in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2020 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated by reference.

Difference between the statutory rate and ETR:

| | Three Months Ended Sept. 30 2021 | 2020 | Nine Months Ended Sept. 30 2021 | 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 |
| Decreases: | | | | |
| Wind PTCs | (12.1) | (8.0) | (20.0) | (13.2) |
| Plant regulatory differences [(a)] | (5.8) | (7.2) | (6.0) | (7.4) |
| NOL carryback | — | (1.9) | — | (1.0) |
| Other (net) | (1.5) | (2.2) | (1.3) | (2.5) |
| Effective income tax rate | 6.6 % | 6.7 % | (1.3)% | 2.0 % |

(a) 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.

**Federal Audits** — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

| Tax Years | Expiration |
|---|---|
| 2014 — 2016 | December 2022 |
| 2018 | September 2022 |

Additionally, the statute of limitations related to certain federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to a federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

**State Audits** — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based tax returns.

As of Sept. 30, 2021, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

| State | Year |
|---|---|
| Colorado | 2014 |
| Minnesota | 2013 |
| Texas | 2012 |
| Wisconsin | 2016 |

- In February 2021, Minnesota concluded its review and commenced an audit of tax years 2015 - 2018. No material adjustments have been proposed.
- In March 2021, Wisconsin began an audit of tax years 2016 - 2019. No material adjustments have been proposed.
- In April 2021, Texas began an audit of tax years 2016 - 2019. No material adjustments have been proposed.
- No other state income tax audits were in progress as of Sept. 30, 2021.

**Unrecognized Benefits —** The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits — permanent vs. temporary:

| (Millions of Dollars) | Sept. 30, 2021 | | Dec. 31, 2020 | |
|---|---|---|---|---|
| Unrecognized tax benefit — Permanent tax positions | $ | 46 | $ | 41 |
| Unrecognized tax benefit — Temporary tax positions | | 11 | | 11 |
| Total unrecognized tax benefit | $ | 57 | $ | 52 |

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

| (Millions of Dollars) | Sept. 30, 2021 | | Dec. 31, 2020 | |
|---|---|---|---|---|
| NOL and tax credit carryforwards | $ | (35) | $ | (31) |

As Internal Revenue Service audits resume and the state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $27 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

| (Millions of Dollars) | Sept. 30, 2021 | | Dec. 31, 2020 | |
|---|---|---|---|---|
| Payable for interest related to unrecognized tax benefits at beginning of period | $ | (3) | $ | — |
| Interest expense related to unrecognized tax benefits | | — | | (3) |
| Payable for interest related to unrecognized tax benefits at end of period | $ | (3) | $ | (3) |

No penalties were accrued related to unrecognized tax benefits as of Sept. 30, 2021 or Dec. 31, 2020.

## 7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the average weighted number of common shares outstanding. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding.

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 diluted EPS is calculated using the treasury stock method.

**Common Stock Equivalents —** Xcel Energy Inc. has common stock equivalents related to time-based equity compensation awards.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock issued to employees is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

Common shares outstanding used in the basic and diluted EPS computation:

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| (Shares in Millions) | 2021 | 2020 | 2021 | 2020 |
| Basic | 539 | 526 | 539 | 526 |
| Diluted [a] | 539 | 528 | 539 | 527 |

[a] Diluted common shares outstanding included common stock equivalents of 0.3 million and 1.6 million for the three months ended Sept. 30, 2021 and 2020, respectively. Diluted common shares outstanding included common stock equivalents of 0.3 million and 1.0 million for the nine months ended Sept. 30, 2021 and 2020, respectively.

## 8. Fair Value of Financial Assets and Liabilities

### Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

***Cash equivalents —*** The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

***Investments in equity securities and other funds —*** Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds' investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

***Investments in debt securities*** — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

***Interest rate derivatives*** — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

***Commodity derivatives*** — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements.

**Non-Derivative Fair Value Measurements**

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $1.2 billion and $981 million as of Sept. 30, 2021 and Dec. 31, 2020, respectively, and unrealized losses were $5 million as of Sept. 30, 2021 and Dec. 31, 2020.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

| | Sept. 30, 2021 | | | | | |
|---|---|---|---|---|---|---|
| | | Fair Value | | | | |
| (Millions of Dollars) | Cost | Level 1 | Level 2 | Level 3 | NAV | Total |
| Nuclear decommissioning fund (a) | | | | | | |
| Cash equivalents | $ 38 | $ 38 | $ — | $ — | $ — | $ 38 |
| Commingled funds | 821 | — | — | — | 1,208 | 1,208 |
| Debt securities | 620 | — | 643 | 15 | — | 658 |
| Equity securities | 407 | 1,178 | 2 | — | — | 1,180 |
| Total | $ 1,886 | $ 1,216 | $ 645 | $ 15 | $ 1,208 | $ 3,084 |

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $204 million of equity method investments and $158 million of rabbi trust assets and miscellaneous investments.

| | Dec. 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| | | Fair Value | | | | |
| (Millions of Dollars) | Cost | Level 1 | Level 2 | Level 3 | NAV | Total |
| Nuclear decommissioning fund (a) | | | | | | |
| Cash equivalents | $ 40 | $ 40 | $ — | $ — | $ — | $ 40 |
| Commingled funds | 787 | — | — | — | 1,041 | 1,041 |
| Debt securities | 528 | — | 572 | 13 | — | 585 |
| Equity securities | 446 | 1,109 | 2 | — | — | 1,111 |
| Total | $ 1,801 | $ 1,149 | $ 574 | $ 13 | $ 1,041 | $ 2,777 |

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $165 million of equity method investments and $154 million of rabbi trust assets and other miscellaneous investments.

For the three and nine months ended Sept. 30, 2021 and 2020, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Sept. 30, 2021:

| | Final Contractual Maturity | | | | |
|---|---|---|---|---|---|
| (Millions of Dollars) | Due in 1 year or Less | Due in 1 to 5 Years | Due in 5 to 10 Years | Due after 10 years | Total |
| Debt securities | $ 2 | $ 153 | $ 204 | $ 299 | $ 658 |

***Rabbi Trusts***

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan.

Cost and fair value of assets held in rabbi trusts:

| | Sept. 30, 2021 | | | | |
|---|---|---|---|---|---|
| | | Fair Value | | | |
| (Millions of Dollars) | Cost | Level 1 | Level 2 | Level 3 | Total |
| Rabbi Trusts (a) | | | | | |
| Cash equivalents | $ 17 | $ 17 | $ — | $ — | $ 17 |
| Mutual funds | 71 | 84 | — | — | 84 |
| Total | $ 88 | $ 101 | $ — | $ — | $ 101 |

| (Millions of Dollars) | Dec. 31, 2020 Cost | Fair Value Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| Rabbi Trusts [(a)] | | | | | |
| Cash equivalents | $ 32 | $ 32 | $ — | $ — | $ 32 |
| Mutual funds | 60 | 70 | — | — | 70 |
| Total | $ 92 | $ 102 | $ — | $ — | $ 102 |

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets.

**Derivative Instruments Fair Value Measurements**

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

***Interest Rate Derivatives*** — Xcel Energy enters into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

As of Sept. 30, 2021, accumulated other comprehensive loss related to interest rate derivatives included $6 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

***Wholesale and Commodity Trading Risk*** — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

***Commodity Derivatives*** — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. The classification of gains or losses for these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms. As of Sept. 30, 2021, Xcel Energy had no commodity contracts designated as cash flow hedges.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

| (Amounts in Millions) [(a)(b)] | Sept. 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| Megawatt hours of electricity | 101 | 87 |
| Million British thermal units of natural gas | 184 | 175 |

(a) Not reflective of net positions in the underlying commodities.
(b) Notional amounts for options included on a gross basis but weighted for the probability of exercise.

***Consideration of Credit Risk and Concentrations*** — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

As of Sept. 30, 2021, six of Xcel Energy's ten most significant counterparties for these activities, comprising $121 million, or 40%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Two of the ten most significant counterparties, comprising $29 million, or 10%, of this credit exposure, were not rated by these external ratings agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. Two of these significant counterparties, comprising $44 million or 14% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Five of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

*Impact of Derivative Activity —*

| (Millions of Dollars) | Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss | Regulatory (Assets) and Liabilities |
|---|---|---|
| **Three Months Ended Sept. 30, 2021** | | |
| **Derivatives designated as cash flow hedges:** | | |
| Interest rate | $ 4 | $ — |
| Total | $ 4 | $ — |
| **Other derivative instruments:** | | |
| Electric commodity | $ — | $ 5 |
| Natural gas commodity | — | 57 |
| Total | $ — | $ 62 |
| **Nine Months Ended Sept. 30, 2021** | | |
| **Derivatives designated as cash flow hedges:** | | |
| Interest rate | $ 5 | $ — |
| Total | $ 5 | $ — |
| **Other derivative instruments:** | | |
| Electric commodity | $ — | $ 18 |
| Natural gas commodity | — | 57 |
| Total | $ — | $ 75 |
| **Three Months Ended Sept. 30, 2020** | | |
| **Other derivative instruments:** | | |
| Electric commodity | $ — | $ (3) |
| Natural gas commodity | — | 2 |
| Total | $ — | $ (1) |
| **Nine Months Ended Sept. 30, 2020** | | |
| **Derivatives designated as cash flow hedges:** | | |
| Interest rate | $ (13) | $ — |
| Total | $ (13) | $ — |
| **Other derivative instruments:** | | |
| Electric commodity | $ — | $ (3) |
| Natural gas commodity | — | (1) |
| Total | $ — | $ (4) |

| (Millions of Dollars) | Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss | Regulatory Assets and (Liabilities) | Pre-Tax Gains (Losses) Recognized During the Period in Income |
|---|---|---|---|
| **Three Months Ended Sept. 30, 2021** | | | |
| **Derivatives designated as cash flow hedges:** | | | |
| Interest rate | $ 2 (a) | $ — | $ — |
| Total | $ 2 | $ — | $ — |
| **Other derivative instruments:** | | | |
| Commodity trading | $ — | $ — | $ 1 (b) |
| Electric commodity | — | 3 (c) | — |
| Total | $ — | $ 3 | $ 1 |
| **Nine Months Ended Sept. 30, 2021** | | | |
| **Derivatives designated as cash flow hedges:** | | | |
| Interest rate | $ 7 (a) | $ — | $ — |
| Total | $ 7 | $ — | $ — |
| **Other derivative instruments:** | | | |
| Commodity trading | $ — | $ — | $ 49 (b) |
| Electric commodity | — | (26) (c) | — |
| Natural gas commodity | — | 8 (d) | (10) (d) |
| Total | $ — | $ (18) | $ 39 |
| **Three Months Ended Sept. 30, 2020** | | | |
| **Derivatives designated as cash flow hedges:** | | | |
| Interest rate | $ 1 (a) | $ — | $ — |
| Total | $ 1 | $ — | $ — |
| **Other derivative instruments:** | | | |
| Commodity trading | $ — | $ — | $ 2 (b) |
| Electric commodity | — | (3) (c) | — |
| Total | $ — | $ (3) | $ 2 |
| **Nine Months Ended Sept. 30, 2020** | | | |
| **Derivatives designated as cash flow hedges:** | | | |
| Interest rate | $ 5 (a) | $ — | $ — |
| Total | $ 5 | $ — | $ — |
| **Other derivative instruments:** | | | |
| Commodity trading | $ — | $ — | $ (1) (b) |
| Electric commodity | — | (6) (c) | — |
| Natural gas commodity | — | 5 (d) | (6) (d) |
| Total | $ — | $ (1) | $ (7) |

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Amounts for both the three and nine months ended Sept. 30, 2021 and 2020 included no settlement gains or losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Remaining settlement losses for both the three and nine months ended Sept. 30, 2021 and 2020 relate to natural gas operations and were recorded to cost of natural gas sold and transported. These gains and losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset or liability, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2021 and 2020.

***Credit Related Contingent Features*** — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. At Sept. 30, 2021 and Dec. 31, 2020, there were $2 million and $4 million, respectively, of derivative liabilities with such underlying contract provisions. Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Sept. 30, 2021 and Dec. 31, 2020, there were approximately $62 million and $60 million, respectively, of derivative liabilities with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2021 and Dec. 31, 2020.

***Recurring Fair Value Measurements*** — Derivative assets and liabilities measured at fair value on a recurring basis:

| | Sept. 30, 2021 | | | | | | Dec. 31, 2020 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fair Value | | | | | | Fair Value | | | | | |
| **(Millions of Dollars)** | Level 1 | Level 2 | Level 3 | Fair Value Total | Netting [(a)] | Total | Level 1 | Level 2 | Level 3 | Fair Value Total | Netting [(a)] | Total |
| **Current derivative assets** | | | | | | | | | | | | |
| Derivatives designated as cash flow hedges: | | | | | | | | | | | | |
| Interest rate | $ — | $ 4 | $ — | $ 4 | $ — | $ 4 | $ — | $ — | $ — | $ — | $ — | $ — |
| Other derivative instruments: | | | | | | | | | | | | |
| Commodity trading | $ 50 | $ 240 | $ 23 | $ 313 | $ (253) | $ 60 | $ 2 | $ 67 | $ 1 | $ 70 | $ (52) | $ 18 |
| Electric commodity | — | — | 83 | 83 | (1) | 82 | — | — | 20 | 20 | (1) | 19 |
| Natural gas commodity | — | 79 | — | 79 | — | 79 | — | 9 | — | 9 | — | 9 |
| Total current derivative assets | $ 50 | $ 323 | $ 106 | $ 479 | $ (254) | 225 | $ 2 | $ 76 | $ 21 | $ 99 | $ (53) | 46 |
| PPAs [(b)] | | | | | | 3 | | | | | | 3 |
| Current derivative instruments | | | | | | $ 228 | | | | | | $ 49 |
| **Noncurrent derivative assets** | | | | | | | | | | | | |
| Other derivative instruments: | | | | | | | | | | | | |
| Commodity trading | $ 23 | $ 72 | $ 99 | $ 194 | $ (129) | $ 65 | $ 8 | $ 66 | $ 8 | $ 82 | $ (62) | $ 20 |
| Total noncurrent derivative assets | $ 23 | $ 72 | $ 99 | $ 194 | $ (129) | 65 | $ 8 | $ 66 | $ 8 | $ 82 | $ (62) | 20 |
| PPAs [(b)] | | | | | | 7 | | | | | | 10 |
| Noncurrent derivative instruments | | | | | | $ 72 | | | | | | $ 30 |

| | Sept. 30, 2021 | | | | | | Dec. 31, 2020 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fair Value | | | | | | Fair Value | | | | | |
| **(Millions of Dollars)** | Level 1 | Level 2 | Level 3 | Fair Value Total | Netting [(a)] | Total | Level 1 | Level 2 | Level 3 | Fair Value Total | Netting [(a)] | Total |
| **Current derivative liabilities** | | | | | | | | | | | | |
| Other derivative instruments: | | | | | | | | | | | | |
| Commodity trading | $ 48 | $ 239 | $ 25 | $ 312 | $ (253) | $ 59 | $ 4 | $ 64 | $ 17 | $ 85 | $ (58) | $ 27 |
| Electric commodity | — | — | 1 | 1 | (1) | — | — | — | 1 | 1 | (1) | — |
| Natural gas commodity | — | — | — | — | — | — | — | 9 | — | 9 | — | 9 |
| Total current derivative liabilities | $ 48 | $ 239 | $ 26 | $ 313 | $ (254) | 59 | $ 4 | $ 73 | $ 18 | $ 95 | $ (59) | 36 |
| PPAs [(b)] | | | | | | 17 | | | | | | 17 |
| Current derivative instruments | | | | | | $ 76 | | | | | | $ 53 |
| **Noncurrent derivative liabilities** | | | | | | | | | | | | |
| Other derivative instruments: | | | | | | | | | | | | |
| Commodity trading | $ 22 | $ 69 | $ 120 | $ 211 | $ (156) | $ 55 | $ 3 | $ 58 | $ 60 | $ 121 | $ (47) | $ 74 |
| Total noncurrent derivative liabilities | $ 22 | $ 69 | $ 120 | $ 211 | $ (156) | 55 | $ 3 | $ 58 | $ 60 | $ 121 | $ (47) | 74 |
| PPAs [(b)] | | | | | | 44 | | | | | | 57 |
| Noncurrent derivative instruments | | | | | | $ 99 | | | | | | $ 131 |

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2021 and Dec. 31, 2020. At both Sept. 30, 2021 and Dec. 31, 2020, derivative assets and liabilities include $15 million of obligations to return cash collateral. At Sept. 30, 2021 and Dec. 31, 2020, derivative assets and liabilities include rights to reclaim cash collateral of $42 million and $6 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, contracts are no longer adjusted to fair value and the previous carrying value of these contracts is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

| (Millions of Dollars) | Three Months Ended Sept. 30 2021 | 2020 |
|---|---|---|
| Balance at July 1 | $ 71 | $ 34 |
| Purchases | 2 | — |
| Settlements | (53) | (17) |
| Net transactions recorded during the period: | | |
| Gains (losses) recognized in earnings (a) | 12 | (25) |
| Net gains recognized as regulatory assets and liabilities | 27 | 2 |
| Balance at Sept. 30 | $ 59 | $ (6) |

| (Millions of Dollars) | Nine Months Ended Sept. 30 2021 | 2020 |
|---|---|---|
| Balance at Jan. 1 | $ (49) | $ 4 |
| Purchases | 65 | 49 |
| Settlements | (101) | (59) |
| Net transactions recorded during the period: | | |
| Gains (losses) recognized in earnings (a) | 59 | (11) |
| Net gains recognized as regulatory assets and liabilities | 85 | 11 |
| Balance at Sept. 30 | $ 59 | $ (6) |

(a) Presented amounts relate to instruments held at the end of the period. The consolidated income statement also includes gains and losses on Level 1 and 2 instruments, and Level 3 instruments settled during the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2021 and 2020.

**Fair Value of Long-Term Debt**

Other financial instruments for which the carrying amount did not equal fair value:

| (Millions of Dollars) | Sept. 30, 2021 Carrying Amount | Sept. 30, 2021 Fair Value | Dec. 31, 2020 Carrying Amount | Dec. 31, 2020 Fair Value |
|---|---|---|---|---|
| Long-term debt, including current portion | $ 21,600 | $ 24,657 | $ 20,066 | $ 24,412 |

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Sept. 30, 2021 and Dec. 31, 2020 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

## 9. Benefit Plans and Other Postretirement Benefits

**Components of Net Periodic Benefit Cost (Credit)**

| (Millions of Dollars) | Three Months Ended Sept. 30 Pension Benefits 2021 | Pension Benefits 2020 | Postretirement Health Care Benefits 2021 | Postretirement Health Care Benefits 2020 |
|---|---|---|---|---|
| Service cost | $ 26 | $ 24 | $ — | $ — |
| Interest cost (a) | 26 | 31 | 4 | 5 |
| Expected return on plan assets (a) | (52) | (52) | (4) | (5) |
| Amortization of prior service credit (a) | — | (1) | (2) | (2) |
| Amortization of net loss (a) | 27 | 25 | 1 | 1 |
| Settlement charge (b) | 39 | — | — | — |
| Net periodic benefit cost (credit) | 66 | 27 | (1) | (1) |
| Effects of regulation | (31) | 4 | 1 | 1 |
| Net benefit cost (credit) recognized for financial reporting | $ 35 | $ 31 | $ — | $ — |

| (Millions of Dollars) | Nine Months Ended Sept. 30 Pension Benefits 2021 | Pension Benefits 2020 | Postretirement Health Care Benefits 2021 | Postretirement Health Care Benefits 2020 |
|---|---|---|---|---|
| Service cost | $ 78 | $ 72 | $ 1 | $ 1 |
| Interest cost (a) | 78 | 94 | 11 | 14 |
| Expected return on plan assets (a) | (155) | (156) | (13) | (15) |
| Amortization of prior service credit (a) | (1) | (3) | (6) | (6) |
| Amortization of net loss (a) | 81 | 74 | 4 | 3 |
| Settlement charge (b) | 39 | — | — | — |
| Net periodic benefit cost (credit) | 120 | 81 | (3) | (3) |
| Effects of regulation | (32) | 7 | 2 | 2 |
| Net benefit cost (credit) recognized for financial reporting | $ 88 | $ 88 | $ (1) | $ (1) |

(a) The components of net periodic cost other than the service cost component are included in the line item "Other (expense) income, net" in the consolidated statements of income or capitalized on the consolidated balance sheets as a regulatory asset.

(b) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In the third quarter of 2021 as a result of lump-sum distributions during the 2021 plan year, Xcel Energy recorded a total pension settlement charge of $39 million, the majority of which was not recognized in earnings due to the effects of regulation. A total of $4 million of that amount was recorded in other expense in the third quarter 2021.

In January 2021, contributions of $125 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2021.

## 10. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

**Legal**

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy’s consolidated financial statements. Legal fees are generally expensed as incurred.

***Gas Trading Litigation*** — e prime is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Multiple lawsuits involving multiple plaintiffs seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

One case remains active which includes an MDL matter consisting of a Wisconsin purported class (Arandell Corp.).

*Breckenridge/Colorado* — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado. Settlement of approximately $3 million was reached in February 2021. In July 2021, the settlement was approved.

*Arandell Corp.* — The trial has been vacated and will be rescheduled after the court rules on the pending motions for reconsideration and for class certification. Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

***Sherco*** — In 2018, NSP-Minnesota and SMMPA (Co-owner of Sherco Unit 3) reached a settlement with GE related to a 2011 incident, which damaged the turbine at Sherco Unit 3 and resulted in an extended outage for repair. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the FCA.

In March 2019, the MPUC approved NSP-Minnesota’s settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota’s prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota’s insurers. In February 2020, the Minnesota Court of Appeals affirmed the district court’s judgment in favor of GE. In March 2020, NSP-Minnesota’s insurers filed a petition seeking additional review by the Minnesota Supreme Court. In April 2020, the Minnesota Supreme Court denied the insurers’ petition for further review, ending the litigation.

In January 2021, the OAG and DOC recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the FCA. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate. A final decision by the MPUC is pending. A loss related to this matter is deemed remote.

***Westmoreland Arbitration*** — In November 2014, insurers of the Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, SMMPA and Western Fuels Association, seeking recovery of alleged $36 million of business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota’s invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota’s failure to conform to industry maintenance standards.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. A final hearing has been scheduled for October 2022. The parties are also required to participate in mediation, which has been scheduled for Nov. 15, 2021. At this stage of the proceeding, a reasonable estimate of damages or range of damages cannot be determined.

***MISO ROE Complaints*** — In November 2013 and February 2015, customer groups filed two ROE complaints against MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. The first complaint requested a reduction in base ROE transmission formula rates from 12.38% to 9.15% for the time period of Nov. 12, 2013 to Feb. 11, 2015, and removal of ROE adders (including those for RTO membership). The second complaint requested, for a subsequent time period, a base ROE reduction from 12.38% to 8.67%.

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C Circuit subsequently vacated and remanded Opinion No. 551.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC’s ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In November 2020, the FERC issued an order (Opinion No. 569-B) in response to rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE effective Sept. 28, 2016, and for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers. Each 10 basis point reduction in ROE for the first complaint period, second complaint period, and subsequent period relative to amounts accrued would reduce Xcel Energy’s net income by $1 million, $1 million and $2 million, respectively.

The MISO TOs and various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the D.C. Circuit. A hearing is expected in the fourth quarter of 2021 with a decision anticipated in the first half of 2022.

***FERC NOPR on ROE Incentive Adders*** — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, NSP-Minnesota, NSP-Wisconsin and SPS would prospectively discontinue charging their current 50 basis point ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, subject to future rate cases.

***SPP OATT Upgrade Costs —*** Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. The D.C. Circuit appeal may resume after that FERC order is issued.

***Contract Termination —*** SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the ERCOT (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

***Comanche Unit 3 Litigation —*** In February 2021, the joint owners of Comanche Unit 3 (CORE Electric Cooperative, formerly known as Intermountain Rural Electrical Association, and Holy Cross Electric) served PSCo with a notice of claim related to Comanche Unit 3's operation and availability.

Discussions with Holy Cross Electric are proceeding pursuant to a contractual dispute resolution process and the amount of any alleged damages depends on multiple factors and is currently unknown.

In September 2021, CORE Electric Cooperative filed a lawsuit in Colorado state court seeking an unspecified amount of damages. CORE Electric Cooperative alleges PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. PSCo is continuing to assess legal options in response to the Complaint including assertions of affirmative defenses.

***GCA NOPR —*** In June 2021, the CPUC issued a NOPR addressing the recovery of costs through the GCA. The proposed rule would establish an annual forecast of GCA costs for each utility and allow each utility to recover only 90%-95% of any costs in excess of the forecasted amount. The proposed rule would allow utilities to earn an incentive equal to an undefined portion of any savings relative to forecasted costs. Comments were filed and requested that the CPUC delay the rule making process until after the 2021-2022 heating season; in part because utilities have already proceeded with purchasing gas for the upcoming heating season in accordance with prior CPUC decisions. In August 2021, the CPUC announced they would postpone a decision to a future date.

**Environmental**

***MGP, Landfill and Disposal Sites***

Xcel Energy is investigating, remediating or performing post-closure actions at 14 MGP, landfill or other disposal sites across its service territories.

Xcel Energy has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

***Environmental Requirements — Water and Waste***

*Coal Ash Regulation —* Xcel Energy's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, Xcel Energy has eight regulated ash units in operation.

Xcel Energy is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, increases above background concentrations were detected at four locations. Based on further assessments, PSCo is evaluating options for corrective action at two locations, one of which indicates potential offsite impacts to groundwater. The total cost is uncertain, but could be up to $35 million. PSCo is continuing to assess the financial and regulatory impacts.

In August 2020, the EPA published its final rule to implement closure by April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. This final rule required Xcel Energy to expedite closure plans for two impoundments.

In October 2020, NSP-Minnesota completed construction and placed in service a new impoundment to replace the clay lined impoundment at a cost of $9 million. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of $4 million. NSP-Minnesota has five years to complete closure activities.

PSCo also built an alternative collection and treatment system to remove the Comanche Station bottom ash pond from service. The total cost of the alternate treatment system is approximately $25 million. PSCo worked expeditiously to meet the April 11, 2021 deadline, but was not able to remove the pond from service until June 18, 2021. PSCo expects to negotiate a compliance order with the EPA. PSCo will also now proceed with closure of the pond, with an estimated cost of $3 million. Closure costs for existing impoundments are included in the calculation of the asset retirement obligation.

**Leases**

Xcel Energy evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

| (Millions of Dollars) | Three Months Ended Sept. 30 2021 | 2020 |
|---|---|---|
| Operating leases | | |
| PPA capacity payments | $ 56 | $ 56 |
| Other operating leases [(a)] | 2 | 5 |
| Total operating lease expense [(b)] | $ 58 | $ 61 |
| Finance leases | | |
| Amortization of ROU assets | $ 2 | $ 2 |
| Interest expense on lease liability | 4 | 4 |
| Total finance lease expense | $ 6 | $ 6 |

(a) Includes short-term lease expense of $1 million and $2 million for 2021 and 2020, respectively.
(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

| (Millions of Dollars) | Nine Months Ended Sept. 30 2021 | 2020 |
|---|---|---|
| Operating leases | | |
| PPA capacity payments | $ 170 | $ 145 |
| Other operating leases [(a)] | 19 | 22 |
| Total operating lease expense [(b)] | $ 189 | $ 167 |
| Finance leases | | |
| Amortization of ROU assets | $ 6 | $ 5 |
| Interest expense on lease liability | 12 | 13 |
| Total finance lease expense | $ 18 | $ 18 |

(a) Includes short-term lease expense of $4 million for 2021 and 2020, respectively.
(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of Sept. 30, 2021:

| (Millions of Dollars) | PPA Operating Leases | Other Operating Leases | Total Operating Leases | Finance Leases [(a)] |
|---|---|---|---|---|
| Total minimum obligation | $ 1,470 | $ 191 | $ 1,661 | $ 246 |
| Interest component of obligation | (221) | (35) | (256) | (173) |
| Present value of minimum obligation | $ 1,249 | 156 | 1,405 | 73 |
| Less current portion | | | (218) | (3) |
| Noncurrent operating and finance lease liabilities | | | $ 1,187 | $ 70 |

(a) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

**VIEs**

Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the IPP.

The utility subsidiaries had approximately 4,062 MW of capacity under long-term PPAs at both Sept. 30, 2021 and Dec. 31, 2020 with entities that have been determined to be VIEs. Xcel Energy concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

**Other**

***Guarantees and Bond Indemnifications*** — Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability under the agreements. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum amount.

As of Sept. 30, 2021 and Dec. 31, 2020, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements. Guarantees and bond indemnities issued and outstanding for Xcel Energy were approximately $60 million and $62 million at Sept. 30, 2021 and Dec. 31, 2020, respectively.

***Other Indemnification Agreements*** — Xcel Energy Inc. and its subsidiaries provide indemnifications through various contracts. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in duration and amount. Maximum future payments under these indemnifications cannot be reasonably estimated.

### 11. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive loss, net of tax, for the three and nine months ended Sept. 30, 2021 and 2020:

| | Three Months Ended Sept. 30, 2021 | | | Three Months Ended Sept. 30, 2020 | | |
|---|---|---|---|---|---|---|
| (Millions of Dollars) | Gains and Losses on Cash Flow Hedges | Defined Benefit Pension and Postretirement Items | Total | Gains and Losses on Cash Flow Hedges | Defined Benefit Pension and Postretirement Items | Total |
| Accumulated other comprehensive loss at July 1 | $ (80) | $ (55) | $ (135) | $ (87) | $ (58) | $ (145) |
| Other comprehensive gain before reclassifications (net of taxes of $1, $—, $— and $—, respectively) | 3 | — | 3 | — | — | — |
| Losses reclassified from net accumulated other comprehensive loss: | | | | | | |
| Interest rate derivatives (net of taxes of $—, $—, $— and $—, respectively) (a) | 2 | — | 2 | 1 | — | 1 |
| Amortization of net actuarial loss (net of taxes of $—, $1, $— and $—, respectively) (b) | — | 4 | 4 | — | 1 | 1 |
| Net current period other comprehensive income | 5 | 4 | 9 | 1 | 1 | 2 |
| Accumulated other comprehensive loss at Sept. 30 | $ (75) | $ (51) | $ (126) | $ (86) | $ (57) | $ (143) |

| | Nine Months Ended Sept. 30, 2021 | | | Nine Months Ended Sept. 30, 2020 | | |
|---|---|---|---|---|---|---|
| (Millions of Dollars) | Gains and Losses on Cash Flow Hedges | Defined Benefit Pension and Postretirement Items | Total | Gains and Losses on Cash Flow Hedges | Defined Benefit Pension and Postretirement Items | Total |
| Accumulated other comprehensive loss at Jan. 1 | $ (85) | $ (56) | $ (141) | $ (80) | $ (61) | $ (141) |
| Other comprehensive gain (loss) before reclassifications (net of taxes of $1, $—, $(3) and $—, respectively) | 4 | — | 4 | (10) | — | (10) |
| Losses reclassified from net accumulated other comprehensive loss: | | | | | | |
| Interest rate derivatives (net of taxes of $1, $—, $1 and $—, respectively) (a) | 6 | — | 6 | 4 | — | 4 |
| Amortization of net actuarial loss (net of taxes of $—, $2, $— and $1, respectively) (b) | — | 5 | 5 | — | 4 | 4 |
| Net current period other comprehensive income (loss) | 10 | 5 | 15 | (6) | 4 | (2) |
| Accumulated other comprehensive loss at Sept. 30 | $ (75) | $ (51) | $ (126) | $ (86) | $ (57) | $ (143) |

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs.

### 12. Segment Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided including the regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo.

These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- **Regulated Electric** — The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel, investments in rental housing projects that qualify for low-income housing tax credits and the operations of MEC until July 2020.

Xcel Energy had equity method investments of $204 million and $165 million as of Sept. 30, 2021 and Dec. 31, 2020, respectively, included in the natural gas utility and all other segments.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments. As an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment. Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations, which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

Xcel Energy's segment information:

| (Millions of Dollars) | Three Months Ended Sept. 30 2021 | Three Months Ended Sept. 30 2020 |
|---|---|---|
| **Regulated Electric** | | |
| Operating revenues — external | $ 3,176 | $ 2,941 |
| Intersegment revenue | — | 1 |
| Total revenues | $ 3,176 | $ 2,942 |
| Net income | 629 | 632 |
| **Regulated Natural Gas** | | |
| Operating revenues — external | $ 268 | $ 219 |
| Intersegment revenue | 1 | — |
| Total revenues | 269 | 219 |
| Net income | 10 | — |
| **All Other** | | |
| Total revenues | $ 23 | $ 22 |
| Net loss | (30) | (29) |
| **Consolidated Total** | | |
| Total revenues | $ 3,468 | $ 3,183 |
| Reconciling eliminations | (1) | (1) |
| Total operating revenues | $ 3,467 | $ 3,182 |
| Net income | 609 | 603 |

| (Millions of Dollars) | Nine Months Ended Sept. 30 2021 | Nine Months Ended Sept. 30 2020 |
|---|---|---|
| **Regulated Electric** | | |
| Operating revenues — external | $ 8,643 | $ 7,430 |
| Intersegment revenue | 1 | 1 |
| Total revenues | $ 8,644 | $ 7,431 |
| Net income | 1,202 | 1,148 |
| **Regulated Natural Gas** | | |
| Operating revenues — external | $ 1,364 | $ 1,082 |
| Intersegment revenue | 2 | 1 |
| Total revenues | 1,366 | 1,083 |
| Net income | $ 161 | $ 111 |
| **All Other** | | |
| Total revenues | 69 | 67 |
| Net loss | $ (81) | $ (74) |
| **Consolidated Total** | | |
| Total revenues | $ 10,079 | $ 8,581 |
| Reconciling eliminations | (3) | (2) |
| Total operating revenues | $ 10,076 | $ 8,579 |
| Net income | 1,282 | 1,185 |

## ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented or are expected to have a material impact in the future. It should be read in conjunction with the accompanying unaudited consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

### Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as 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.

### 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 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.

## Results of Operations

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. Diluted earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole.

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.

### Summary of Earnings

***Xcel Energy*** — Xcel Energy's GAAP diluted earnings were $1.13 per share in 2021 compared with $1.14 per share in 2020 for the third quarter of 2021 and increased $0.13 per share year-to-date. 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.

***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 EIP funds equity method investments.

### *Changes in GAAP and Ongoing Diluted EPS*

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 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 PTCs and plant regulatory amounts, which are primarily offset in electric margin.

### Statement of Income Analysis

The following summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

***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.

Degree-day or 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. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. 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 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 |
| HDD | (50.5)% | 48.4 % | (65.8)% | 0.1 % | (2.8) % | 1.5 % |
| CDD | 18.1 | 20.7 | (9.1) | 11.7 | 21.2 | (8.1) |
| THI | 6.2 | 4.6 | 2.4 | 25.5 | 7.0 | 18.7 |

***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.

Electric revenues and margin:

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| (Millions of Dollars) | 2021 | 2020 | 2021 | 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.

Natural gas revenues and margin:

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| (Millions of Dollars) | 2021 | 2020 | 2021 | 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 |

### Non-Fuel Operating Expenses and Other Items

***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 1 to the consolidated financial statements) | 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*** — 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. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. 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.

## Other

### 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 DOC recommended disallowances of $21 million related to the utilization of natural gas storage. The 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.<br><br>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 gas costs and $4 million in incremental steam costs over 24 months with no financing charge.<br><br>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 Note 1 of the accompanying consolidated financial statements for further discussion.<br><br>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.<br><br>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 SPP resettlements and continued increases in natural gas prices. The proposed recovery remains over 24 months beginning in February 2022.<br><br>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. |

### COVID-19

Although the COVID-19 pandemic has led to numerous challenges, Xcel Energy believes its risk management program, including business continuity and disaster recovery planning, will continue to allow us to proactively manage and successfully navigate challenges, risks and uncertainties.

Continued uncertainty remains regarding COVID-19, the pace of economic recovery, any potential re-shutdowns or reinstatement of business restrictions both domestically and globally and potential workforce impacts resulting from federal laws regarding vaccinations.

An overview of certain risk considerations or areas which have or could significantly impact us is as follows:

***Sales*** — Xcel Energy has experienced and may continue to experience sales volatility and shifts between residential and C&I sales as a result of COVID-19. Xcel Energy has decoupling and sales true-up mechanisms in Minnesota (all electric classes) and Colorado (residential and non-demand small C&I electric classes), which mitigate the impact of changes to sales levels as compared to a baseline.

***Bad Debt*** — Bad debt expense could significantly increase due to pandemic related economic impacts, customer hardship, federal or state legislation and regulatory orders. However, several of our commissions have approved the deferral of incremental COVID-19 related costs, including bad debt expense.

Xcel Energy has received orders in Colorado, Wisconsin, Texas, New Mexico, North Dakota, South Dakota and Michigan, allowing regulatory deferral of incremental COVID-19 costs as a regulatory asset subject to future determination of amount and timing of recovery. Through the Minnesota electric rate case stay-out, NSP-Minnesota agreed to not seek recovery of incremental COVID-19 related costs. As part of the approved North Dakota electric rate case settlement agreement, the Company will not defer COVID-19 impacts. The impact related to the North Dakota natural gas utility will continue to be deferred.

In October 2021, a settlement was reached on Winter Storm Uri costs and also addressed bad debt expense related to COVID-19 in Colorado. See Note 1 of the accompanying consolidated financial statements for further discussion.

The majority of wholesale customers are subject to formula transmission and production rates, which true-up rates to actual costs to serve.

***Supply Chain and Capital Expenditures*** — Xcel Energy's ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Overall, as a result of COVID-19, manufacturing processes have experienced disruptions related to scarcity of raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, storms and labor shortages. Xcel Energy continues to monitor the availability of materials and seek alternative suppliers as necessary.

## Public Utility Regulation

The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and West Gas Interstate. Xcel Energy is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico, and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. Our utility subsidiaries request changes in utility rates through commission filings. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact Xcel Energy's results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2020 and in Item 2 of Xcel Energy's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2021 and Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2021 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

### NSP-Minnesota

***Pending and Recently Concluded Regulatory Proceedings***

| Proceeding | Amount (in millions) | Filing Date | Approval |
|---|---|---|---|
| 2020 TCR Electric Rider | $82 | November 2019 | Pending |
| 2021 GUIC Natural Gas Rider | 27 | October 2020 | Pending |
| 2021 RES Electric Rider | 189 | November 2020 | Pending |
| 2020 North Dakota Electric Rate Case | 19 | November 2020 | Received |
| 2021 North Dakota Natural Gas Rate Case | 7 | September 2021 | Pending |
| 2022 Minnesota Electric Rate Case | 677 | October 2021 | Pending |
| 2022 Minnesota Natural Gas Rate Case | TBD | November 2021 | Pending |

*Additional Information:*

*2020 TCR Electric Rider* — In November 2019, NSP-Minnesota filed the TCR Rider based on a ROE of 9.06%. An MPUC decision is pending.

*2021 GUIC Natural Gas Rider* — In October 2020, NSP-Minnesota filed the GUIC Rider based on a ROE of 9.04%. An MPUC decision is pending.

*2021 RES Electric Rider* — In November 2020, NSP-Minnesota filed the RES Rider. The requested amount includes a true-up (2019 and 2020 riders) of $96 million and the 2021 requested amount of $93 million. The filing included a ROE of 9.06%. An MPUC decision is pending.

*2020 North Dakota Electric Rate Case* — In November 2020, NSP-Minnesota filed a rate case with the 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 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.

*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.

*2022 Minnesota Electric Rate Case* — On Oct. 25, 2021, NSP-Minnesota filed a three-year electric rate case with the 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.

*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.

***Minnesota Resource Plan*** — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034.

In June 2021, NSP-Minnesota filed an alternative plan that would be expected to reduce carbon emissions 85% by 2030 and has a lower projected cost than either of the previously submitted plans. The alternative plan includes the following:

- Removing the planned Sherco combined cycle natural gas plant.
- Retiring all coal generation by 2030 with reduced operations at some units prior to retirement, including early retirement of the A.S. King coal plant (511 MW) in 2028 and Sherco 3 coal plant (517 MW) in 2030.
- Extending the life of the Monticello nuclear plant from 2030 to 2040.
- Continuing to run the Prairie Island nuclear generating plant at least through current end of life (2033 and 2034).
- Adding 3,150 MW of universal solar, 2,650 MW of wind and 250 MW of storage.
- Adding 800 MW of new hydrogen-ready combustion-turbines and repowering 300 MW of blackstart combustion-turbines.
- Adding 1,900 MW of other firm dispatchable resources.
- Constructing 155 miles of transmission lines.
- Achieving 780 gigawatt hours in energy efficiency savings annually through 2034.
- Adding 400 MW of incremental demand response by 2023 and a total of 1,500 MW of demand response by 2034.

The MPUC is anticipated to make a final decision in late 2021 or early 2022.

***Minnesota Relief and Recovery*** — In 2020, the MPUC opened a docket and invited utilities in the state to submit potential projects that would create jobs and help jump start the economy to offset the impacts of COVID-19. The status of the various proposals is listed below:

- In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects and 20 MW of wind projects under PPAs. These projects are estimated to save customers approximately $160 million over the next 25 years.
- In April 2021, NSP-Minnesota proposed to add 460 MWs of solar facilities at the Sherco site with an incremental investment of approximately $575 million. A MPUC decision is expected in early 2022.
- In June 2021, the MPUC approved NSP-Minnesota's proposal to acquire a 120 MW repowered wind farm from ALLETE for $210 million.
- The MPUC is also considering NSP-Minnesota's revised proposal to provide $40 million of incremental electric vehicle rebates.

**Nuclear Power Operations**

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 12 to the consolidated financial statements of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2020, for further information. The circumstances set forth in Nuclear Power Operations included in Item 7 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2020, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated by reference.

**NSP-Wisconsin**

***Pending and Recently Concluded Regulatory Proceedings***

| Proceeding | Amount (in millions) | Filing Date | Approval |
|---|---|---|---|
| Electric and Natural Gas Settlement | $66 | July 2021 | Pending |
| Michigan Rate Case | $2.5 | September 2021 | Pending |

*Additional Information:*

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%) increase for 2023.

Key elements of the settlement include:

- 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.

Michigan Electric Rate Case — In September 2021, NSP-Wisconsin 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**

***Pending and Recently Concluded Regulatory Proceedings***

| Proceeding | Amount (in millions) | Filing Date | Approval |
|---|---|---|---|
| PSIA Extension | $9 | February 2021 | Received |
| Electric Rate Case | $470 | July 2021 | Pending |

*Additional Information:*

PSIA Rider Extension — In February 2021, PSCo requested to extend its PSIA rider for three years (through the end of 2024), which would recover $464 million in project costs over a three-year period. 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. In October 2021, the CPUC approved a settlement agreement with CPUC Staff and the COEO to allow the rider to end at the end of 2021, transfer the investments recovered under the rider to base rates January 1, 2022, and defer $9 million of depreciation expense and return on $143 million in project costs in 2022.

*Colorado Electric Rate Request* — In July 2021, PSCo filed a request with the 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.

| Revenue Request (millions of dollars) | 2022 |
|---|---|
| Changes since 2019 rate case: | |
| Plant-related growth | $ 95 |
| Advanced grid intelligence and security | 73 |
| Updated cost of capital | 53 |
| New depreciation rates | 43 |
| Wildfire mitigation | 25 |
| Property taxes | 25 |
| Amortization of previously approved deferrals | 17 |
| Other | 12 |
| **Net increase to revenue** | **343** |
| Roll-in of previously authorized costs: | |
| TCA rider revenues and Cheyenne Ridge costs | 127 |
| **Total base revenue request** | **$ 470** |
| | |
| **Expected average 2022 rate base (billions of dollars)** | **$ 10.3** |

***2019 Electric Rate Case Appeal*** — In August 2020, PSCo filed an appeal with the Denver District Court seeking a review of CPUC decisions on gains and losses on sales of assets, oil and gas royalty revenues, Board of Directors equity compensation and a true-up surcharge to collect the difference between what rates should have been in place from February through August 2020 (based on the CPUC's decision on the Company's Application for Reconsideration, Rehearing or Reargument) and what rates were actually in place. A decision is pending.

***Decoupling Filing*** — PSCo's 2019 Electric Rate Case included a decoupling program, effective April 1, 2020 through Dec. 31, 2023. The program applies to Residential and metered small C&I customers who do not pay a demand charge. The program includes a refund and surcharge cap not to exceed 3% of forecasted base rate revenue for a specified period.

In April 2021, PSCo made its annual filing for 2020, and the revised tariff went into effect by operation of law on June 1, 2021. In the annual filing review, the CPUC indicated they may pursue reopening the case in order to revisit the cap. As of Sept. 30, 2021, PSCo has recognized a refund for Residential customers and a surcharge for C&I customers based on 2020 results and 2021 estimated amounts to date.

In October 2021, a settlement was reached on Winter Storm Uri costs and also addressed certain components of decoupling. See Note 1 of the accompanying consolidated financial statements for further discussion.

***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, proposing a 560-mile, 345 kilovolt double circuit transmission network to enable approximately 4,000-5,000 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 - $1.0 billion. A CPUC decision regarding the Power Pathway project, as well as the May Valley - Longhorn Extension, is expected by February 2022.

***KEPCO Filing*** — In September 2020, PSCo filed with the CPUC for approval to terminate a solar PPA with KEPCO Solar of Alamosa, Inc. and establish a regulatory asset to recover transaction costs of approximately $41 million. However, the ALJ ruled against approval of the Termination Agreement. In July 2021, the CPUC upheld the ALJ's recommended decision.

***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 is expected to result in an 80% renewable fuel mix and an 85% carbon emissions reduction target by 2030 (from 2005 levels).

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 MW of wind power.
- 1,600 MW of large-scale solar power.
- 400 MW of energy storage.
- 1,300 MW of flexible dispatchable resources (including natural gas).

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 value and decommissioning costs for Comanche Unit 3 upon retirement in 2040.

In October 2021, intervenors filed varying proposals related to Comanche Unit 3's retirement date and commencement of Comanche Unit 3 reduced operations.

A CPUC decision on the resource plan is expected in the first quarter of 2022 with the competitive solicitation for resource additions expected in the second quarter 2022. Incremental generation system costs to meet carbon emission reduction targets are proposed to be recovered through a Clean Energy Plan Rider.

***PSCo — Comanche Unit 3*** — PSCo is part owner and operator of Comanche Unit 3, a 750 MW, coal-fueled electric generating unit. In January 2020, the unit experienced a turbine failure causing the unit to be taken offline for repairs, which were completed in June 2020. During start-up, the unit experienced a loss of turbine oil, which damaged the unit. Comanche Unit 3 recommenced operations in January 2021. Replacement and repair of damaged systems in excess of a $2 million deductible are expected to be recovered through insurance policies. PSCo incurred replacement power costs of approximately $16 million during the outage.

In October 2020, the CPUC initiated a review of Comanche Unit 3's performance. In March 2021, the CPUC Staff issued a report, which noted higher-than average outages and included criticisms of PSCo's operations of Comanche Unit 3 over the last ten years. The report recommended thorough explanation of the future of Comanche Unit 3 operations in the next resource plan, performance standards for all company-owned generation and a review of outage and repair costs in the upcoming proceedings.

In October 2021, a comprehensive settlement on several regulatory issues was reached, which also addressed treatment of Comanche Unit 3 replacement power costs. See Note 1 of the accompanying consolidated financial statements for further discussion.

**SPS**

***Pending and Recently Concluded Regulatory Proceedings***

| Proceeding | Amount (in millions) | Filing Date | Approval |
|---|---|---|---|
| 2021 New Mexico Electric Rate Case | $62 | June 2021 | Pending |
| 2021 Texas Electric Rate Case | $140 | February 2021 | Pending |

*Additional Information:*

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

The request was 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.

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.

The stipulation is subject to NMPRC approval. A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

2021 Texas Electric Rate Case — In February 2021, SPS filed an electric rate case with the 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.

**Environmental**

**Affordable Clean Energy**

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. If the new rules require additional investment, Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

**Emerging Regulation**

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention by environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our operations, financial condition or cash flows. Xcel Energy will continue to monitor these regulatory developments and their potential impact on its operations.

**Potential Tax Reform**

The U.S. Congress is currently discussing potential proposals that may impact federal tax law. Proposals are being made in conjunction with a bipartisan infrastructure bill and a larger reconciliation package. At this time, it is unknown what, if any, changes may ultimately occur. If the tax laws were changed and there was an increase in the federal tax rate, Xcel Energy would expect to defer the impact and ultimately recover the incremental tax expense from our customers consistent with precedent in the federal tax law change in 2017. As a result, we would not expect the impact of a change in the tax rate to have a material impact on our earnings.

### Derivatives, Risk Management and Market Risk

We are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

See Note 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While we expect that the counterparties will perform under the contracts underlying its derivatives, the contracts expose us to some credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and Xcel Energy's ability to earn a return on short-term investments.

**Commodity Price Risk** — We are exposed to commodity price risk in our electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows us to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

**Wholesale and Commodity Trading Risk** — Xcel Energy conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Our risk management policy allows management to conduct these activities within guidelines and limitations as approved by our risk management committee.

Fair value of net commodity trading contracts as of Sept. 30, 2021:

| | Futures / Forwards Maturity | | | | |
|---|---|---|---|---|---|
| **(Millions of Dollars)** | **Less Than 1 Year** | **1 to 3 Years** | **4 to 5 Years** | **Greater Than 5 Years** | **Total Fair Value** |
| NSP-Minnesota [(a)] | $ (8) | $ (7) | $ (1) | $ (1) | $ (17) |
| NSP- Minnesota [(b)] | 2 | 7 | (6) | 2 | 5 |
| PSCo [(a)] | 10 | 8 | 1 | 1 | 20 |
| PSCo [(b)] | (30) | (43) | (4) | — | (77) |
| | $ (26) | $ (35) | $ (10) | $ 2 | $ (69) |

| | Options Maturity | | | | |
|---|---|---|---|---|---|
| **(Millions of Dollars)** | **Less Than 1 Year** | **1 to 3 Years** | **4 to 5 Years** | **Greater Than 5 Years** | **Total Fair Value** |
| NSP-Minnesota [(b)] | $ 1 | $ — | $ — | $ 4 | $ 5 |
| PSCo [(b)] | 25 | 22 | — | — | 47 |
| | $ 26 | $ 22 | $ — | $ 4 | $ 52 |

(a) Prices actively quoted or based on actively quoted prices.
(b) Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the nine months ended Sept. 30:

| **(Millions of Dollars)** | **2021** | **2020** |
|---|---|---|
| Fair value of commodity trading net contracts outstanding at Jan. 1 | $ (54) | $ (59) |
| Contracts realized or settled during the period | (35) | (9) |
| Commodity trading contract additions and changes during the period | 72 | 10 |
| Fair value of commodity trading net contracts outstanding at Sept. 30 | $ (17) | $ (58) |

At Sept. 30, 2021, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pre-tax income from continuing operations by approximately $23 million, whereas a 10% decrease would decrease pre-tax income from continuing operations by approximately $23 million. At Sept. 30, 2020, a 10% increase in market prices for commodity trading contracts would increase pre-tax income from continuing operations by approximately $14 million, whereas a 10% decrease would decrease pre-tax income from continuing operations by approximately $14 million. Market price movements can exceed 10% under abnormal circumstances.

The utility subsidiaries' commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on the outstanding contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, excluding both non-derivative transactions and derivative transactions designated as normal purchase, normal sales, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period, were as follows:

| **(Millions of Dollars)** | **Three Months Ended Sept. 30** | **VaR Limit** | **Average** | **High** | **Low** |
|---|---|---|---|---|---|
| 2021 | $ 1.9 | $ 3.0 | $ 1.5 | $ 2.2 | $ 0.9 |
| 2020 | 1.2 | 3.0 | 1.0 | 1.3 | 0.8 |

A short-term increase in VaR occurred during the week of Feb. 12, 2021 through Feb. 18, 2021. On Feb. 17, 2021, the portfolio VaR reached a high of $52 million. This increase in VaR was driven by the unprecedented market conditions during Winter Storm Uri. Prior to this widespread weather event, VaR was $1 million and returned to $1 million by Feb. 19, 2021.

***Nuclear Fuel Supply*** — NSP-Minnesota has contracted for approximately 23% of its 2021 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 30% of its average enriched nuclear material requirements from these sources. NSP-Minnesota is able to manage nuclear fuel supply with alternate potential sources. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

**Interest Rate Risk** — Xcel Energy is subject to interest rate risk. Our risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Sept. 30, 2021 and 2020, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pre-tax interest expense annually by approximately $18 million and $6 million, respectively.

See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets and/or benefit costs.

**Credit Risk** — Xcel Energy is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy maintains credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Sept. 30, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $73 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $43 million. At Sept. 30, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $29 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $3 million.

Xcel Energy conducts credit reviews for all counterparties and employs credit risk control, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored and when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase our credit risk.

## FAIR VALUE MEASUREMENTS

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value.

The Company's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

See Note 8 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

**Commodity Derivatives** — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 2021.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Sept. 30, 2021.

## LIQUIDITY AND CAPITAL RESOURCES

### Cash Flows

***Operating Cash Flows***

| (Millions of Dollars) | | Nine Months Ended Sept. 30 |
|---|---|---|
| Cash provided by operating activities — 2020 | $ | 2,174 |
| Components of change — 2021 vs. 2020 | | |
| Higher net income | | 97 |
| Non-cash transactions [(a)] | | 69 |
| Changes in working capital [(b)] | | 111 |
| Changes in net regulatory and other assets and liabilities | | (872) |
| Cash provided by operating activities — 2021 | $ | 1,579 |

(a) Non-cash transactions applicable to net income (e.g., depreciation and amortization, nuclear fuel amortization, changes in deferred income taxes, allowance for equity funds used during construction, etc.).

(b) Working capital includes accounts receivable, accrued unbilled revenues, inventories, accounts payable, other current assets and other current liabilities.

Net cash provided by operating activities decreased $595 million for the nine months ended Sept. 30, 2021 compared with the prior year. The decrease was primarily due to the deferral of net natural gas, fuel and purchased energy costs related to Winter Storm Uri in the first quarter.

***Investing Cash Flows***

| (Millions of Dollars) | | Nine Months Ended Sept. 30 |
|---|---|---|
| Cash used in investing activities — 2020 | $ | (3,021) |
| Components of change — 2021 vs. 2020 | | |
| Decreased capital expenditures | | 649 |
| Sale of MEC in 2020 | | (684) |
| Other investing activities | | (9) |
| Cash used in investing activities — 2021 | $ | (3,065) |

Net cash used in investing activities increased $44 million for the nine months ended Sept. 30, 2021 compared with the prior year. The decrease in capital expenditures was primarily due to the purchase of MEC in January 2020, which was subsequently sold in July 2020.

***Financing Cash Flows***

| (Millions of Dollars) | | Nine Months Ended Sept. 30 |
|---|---|---|
| Cash provided by financing activities — 2020 | $ | 1,484 |
| Components of change — 2021 vs. 2020 | | |
| Higher debt issuances | | 238 |
| Lower repayments of long-term debt | | 302 |
| Higher dividends paid to shareholders | | (60) |
| Other financing activities | | 24 |
| Cash provided by financing activities — 2021 | $ | 1,988 |

Net cash provided by financing activities increased $504 million for the nine months ended Sept. 30, 2021 compared with the prior year. The increase was primarily attributable to the amount/timing of debt issuances and repayments, partially attributable to Winter Storm Uri.

**Capital Requirements**

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

**Pension Fund** — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities, and alternative investments, including private equity, real estate and hedge funds.

- In January 2021, contributions of $125 million were made across four of Xcel Energy's pension plans.
- In 2020, contributions of $150 million were made across four of Xcel Energy's pension plans.
- For future years, contributions will be made as deemed appropriate based on evaluation of various factors including the funded status of the plans, minimum funding requirements, interest rates and expected investment returns.

**Capital Sources**

***Short-Term Funding Sources*** — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on financing needs for construction expenditures, working capital and dividend payments.

***Short-Term Investments*** — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts.

***Revolving Credit Facilities*** — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2024 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

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 |

(a) Credit facilities expire in June 2024.
(b) Includes outstanding commercial paper and letters of credit.

**Bilateral Credit Agreement**

In April 2021, NSP-Minnesota's uncommitted $75 million bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Sept. 30, 2021, NSP-Minnesota's outstanding letters of credit under the bilateral credit agreement were as follows:

| (Millions of Dollars) | Limit | Amount Outstanding | Available |
|---|---|---|---|
| NSP-Minnesota | $ 75 | $ 41 | $ 34 |

***Short-Term Debt*** — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $1.25 billion for Xcel Energy Inc.
- $700 million for PSCo.
- $500 million for NSP-Minnesota.
- $500 million for SPS.
- $150 million for NSP-Wisconsin.

In addition, in February 2021, Xcel Energy Inc. entered into a $1.2 billion 364-Day Term Loan Agreement that matures Feb. 17, 2022. Xcel Energy has an option to extend through Feb. 16, 2023.

Short-term debt outstanding for Xcel Energy was as follows:

| (Amounts in Millions, Except Interest Rates) | Three Months Ended Sept. 30, 2021 | Year Ended Dec. 31, 2020 |
|---|---|---|
| Borrowing limit | $ 4,300 | $ 3,100 |
| Amount outstanding at period end | 1,747 | 584 |
| Average amount outstanding | 1,742 | 1,126 |
| Maximum amount outstanding | 1,857 | 2,080 |
| Weighted average interest rate, computed on a daily basis | 0.57 % | 1.45 % |
| Weighted average interest rate at period end | 0.56 | 0.23 |

***Money Pool*** — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions.

***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 Planned 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 million | 2021 Q4 | 5 Year/10 Year | TBD |
| PSCo | First Mortgage Bonds | 750 million | Completed | 10 Year | 1.88 % |
| SPS | First Mortgage Bonds | 250 million | Completed | 29 Year | 3.15 |
| NSP-Minnesota | First Mortgage Bonds | 425 million | Completed | 10 Year | 2.25 |
| NSP-Minnesota | First Mortgage Bonds | 425 million | Completed | 31 Year | 3.20 |
| NSP-Wisconsin | First Mortgage Bonds | 100 million | 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.

**Off-Balance-Sheet Arrangements**

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

**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.

## ITEM 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes to the market risk disclosure included in our Annual Report on Form 10-K for the year ended Dec. 31, 2020 under "Derivatives, Risk Management and Market Risk."

## ITEM 4 — CONTROLS AND PROCEDURES

### Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Sept. 30, 2021, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

### Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting.

# PART II — OTHER INFORMATION

## ITEM 1 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

See Note 10 to the consolidated financial statements and Part I Item 2 for further information.

## ITEM 1A — RISK FACTORS

Xcel Energy's risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2020, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

## ITEM 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

### Purchases of Equity Securities by the Issuer and Affiliated Purchasers

For the quarter ended Sept. 30, 2021, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

## ITEM 6 — EXHIBITS

* Indicates incorporation by reference

| Exhibit Number | Description | Report or Registration Statement | Exhibit Reference |
|---|---|---|---|
| 3.01* | Amended and Restated Articles of Incorporation of Xcel Energy Inc., dated May 17, 2012 | Xcel Energy Inc. Form 8-K dated May 16, 2012 | 3.01 |
| 3.02* | Bylaws of Xcel Energy Inc. as Amended on April 3, 2020 | Xcel Energy Inc Form 8-K dated April 3, 2020 | 3.01 |
| 4.01* | Supplemental Indenture dated as of July 19, 2021 between Northern States Power Company and U.S. Bank National Association, as successor Trustee, creating 2.82% First Mortgage Bonds, Series due May 1, 2051 | NSP-Wisconsin Form 8-K dated July 20, 2021 | 4.01 |
| 10.01 | Summary of Non-Employee Director Compensation, effective as of October 1, 2021 | | |
| 31.01 | Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. | | |
| 31.02 | Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. | | |
| 32.01 | Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. | | |
| 101.INS | Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. | | |
| 101.SCH | Inline XBRL Schema | | |
| 101.CAL | Inline XBRL Calculation | | |
| 101.DEF | Inline XBRL Definition | | |
| 101.LAB | Inline XBRL Label | | |
| 101.PRE | Inline XBRL Presentation | | |
| 104 | Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101) | | |

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**XCEL ENERGY INC.**

October 28, 2021

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)