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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2024 or

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

For the transition period from ____ to ____

001-3034
(Commission File Number)

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS 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)

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 per share	XEL	Nasdaq Stock Market LLC

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

As of June 30, 2024, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $29,767,371,894.

As of Feb. 20, 2025, there were 574,552,694 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for its 2025 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K.

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PART I
ITEM 1 — BUSINESS

Definitions of Abbreviations

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

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
Nicollet Project Holdings	Nicollet Project Holdings, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FASB	Financial accounting standards board
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPUC	Minnesota Public Utilities Commission
MPSC	Michigan Public Service Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utility Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DSM	Demand side management
FCA	Fuel clause adjustment
GCA	Gas cost adjustment
RES	Renewable energy standard

Other

ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
ARO	Asset retirement obligation
ARRR	Application for rehearing, reargument or reconsideration
ASC	Financial Accounting Standards Board Accounting Standards Codification
ASU	Accounting standards update
ATM	At-the-market
C&I	Commercial and industrial
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFO	Chief financial officer
CIG	Colorado Interstate Gas Company, LLC
CON	Certificate of need
CO_2	Carbon dioxide
CORE	CORE Electric Cooperative
CPCN	Certificate of public convenience and necessity
CSPV	Crystalline silicon photovoltaic
CWIP	Construction work in progress
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
INPO	Institute of Nuclear Power Operations
IRA	Inflation Reduction Act
IPP	Independent power producing entity
IRP	Integrated resource plan
ISO	Independent system operator
ITC	Investment tax credit
LP&L	Lubbock Power & Light
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOL	Net operating loss
NOx	Nitrogen oxides
O&M	Operating and maintenance
ONES	Operations, Nuclear, Environmental and Safety
PFAS	Per- and polyfluoroalkyl substances
PIM	Performance incentive mechanism
Post-65	Post-Medicare
PPA	Power purchase agreement
Pre-65	Pre-Medicare
PSPS	Public safety power shutoff
PTC	Production tax credit
RDF	Refuse-derived fuel
REC	Renewable energy credit

RFP	Request for proposal
ROE	Return on equity
ROU	Right-of-use
RTO	Regional transmission organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SPP	Southwest Power Pool, Inc.
SRP	System resiliency plan
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TSR	Total shareholder return
VaR	Value at risk
VIE	Variable interest entity
WACC	Weighted average cost of capital
WMP	Wildfire mitigation plan

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Where to Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available through its website, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC.

The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy's website is not a part of, or incorporated by reference in, this annual report on Form 10-K. Xcel Energy intends to make future announcements regarding Company developments and financial performance through its website, www.xcelenergy.com, as well as through press releases, filings with the SEC, conference calls and webcasts.

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 those relating to 2025 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, expected pension contributions and expected impact on our results of operations, financial condition and cash flows of interest rate changes, increased credit exposure, and legal proceeding outcomes, 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 elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2024 (including risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee workforce and third-party contractor factors; violations of our Codes of Conduct; our ability to recover costs and our subsidiaries' ability to recover costs from customers; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including recessionary conditions, 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; uncertainty regarding epidemics; effects of geopolitical events, including war and acts of terrorism; cybersecurity threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather events; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties and wildfire damages in excess of liability insurance coverage; regulatory changes and/or limitations related to the use of natural gas as an energy source; challenging labor market conditions and our ability to attract and retain a qualified workforce; and our ability to execute on our strategies or achieve expectations related to environmental, social and governance matters including as a result of evolving legal, regulatory and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets.

Overview

Xcel Energy (the "Company") is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). The Company serves customers in eight states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.9 million electric customers and 2.2 million natural gas customers through four utility subsidiaries (NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. The Company's nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings.

XELogo-185.jpg

Subsidiary / Affiliate	Function
NSP-Minnesota	Electric & Gas
NSP-Wisconsin	Electric & Gas
PSCo	Electric & Gas
SPS	Electric
WGI	Interstate gas pipeline
WYCO	Gas storage and transportation
Other Subsidiaries	See Note 1 to the consolidated financial statements for further information.

Utility Subsidiary Overview	
Electric customers	3.9 million
Natural gas customers	2.2 million
Total assets	$70 billion
Electric generating capacity (owned)	20,426 MW
Natural gas storage capacity	53.3 Bcf
Electric transmission lines (conductor miles)	111,000 miles
Electric distribution lines (conductor miles)	221,000 miles
Natural gas transmission lines	2,100 miles
Natural gas distribution lines	38,000 miles

Service Territory

serviceterritorymap-185-blk-withMI.jpg

Strategy

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need. We will deliver on this vision while offering a competitive total return to our shareholders. Our mission is to make energy work better for our customers, helping them thrive every day.

We execute on our vision and mission through three strategic priorities.

OUR CUSTOMERS	OUR PEOPLE	OUR PERFORMANCE
Enhance their experience with Xcel Energy and keep their bills as low as possible	Provide a rewarding employee experience, with development, engagement and growth	Deliver excellent operational, financial and clean energy performance

Our employees are guided by four corporate values: Connected, Committed, Safe and Trustworthy.

Our values, culture and Code of Conduct serve as the foundation upon which Xcel Energy's employees, Board of Directors, contractors and suppliers approach their work in delivering on our three strategic priorities.

OUR CUSTOMERS

Xcel Energy has invested more than $2 billion over the past decade in a portfolio of renewable and conservation programs that provide customers with clean energy options and help keep bills low. New demand remains robust in our territories, including load growth from new data centers, industrial electrification and electric vehicle adoption. As such, we are transforming and expanding our electric grid to accommodate load growth, renewable energy and distributed energy resources.

We are in the process of installing smart electric meters, which will deliver customer and operational benefits, providing near-real-time communication, allowing customers to know how much energy they are using and what it will cost. In addition, customers will have new digital tools to make it easier to access their energy information, gain useful insights to understand and manage their energy use and make energy choices that lower their bills.

Customer affordability is critical to successful strategy execution. Since 2020, our lean operating program has generated nearly $500 million of sustainable savings for our customers, while improving operating outcomes and reducing enterprise risk. At the same time, our Steel for Fuel strategy has saved customers nearly $5 billion since 2017 in avoided fuel costs and PTCs.

In turn, we delivered our electric and natural gas products in 2024 at a price that is lower than it was ten years ago on an inflation adjusted basis. Since 2014, our average residential electric bill growth has been 1.7% per year and natural gas bills have declined 0.6% per year on a nominal basis. Additionally, based on available EIA data, the five year average residential electric and natural gas bills for an Xcel Energy customer were 28% and 12% below the national average.

Going forward, our goal is to enable the clean energy transition while keeping long-term customer bill growth below the rate of inflation through initiatives including conservation programs, O&M cost control, our One Xcel Energy Way lean management initiative, advanced operational technologies and our Steel for Fuel program.

We provide a fundamental service, powering our communities with safe, reliable, competitively priced and increasingly clean energy.

Investing in our communities is important to our collective success. We initiated 24 economic development projects for our local communities in 2024, which are projected to create more than $5.1 billion in capital investments and nearly 3,200 jobs. Nearly 59% of our supply chain spend was local.

Approximately 280 employees served on more than 480 nonprofit organizations or local community boards, providing over 26,000 volunteer hours in 2024. Our annual Day of Service attracted 2,200 people who volunteered over 7,900 combined hours at over 110 nonprofit projects across the company's service footprint.

In 2024, the Xcel Energy Foundation contributed $5 million to 390 nonprofit organizations that support its three charitable giving focus areas of STEM Career Pathways, Environmental Sustainability, and Community Vitality. Through our 2024 Power Your Purpose Giving Campaign, Xcel Energy employees, contractors and retirees donated more than $2 million to over 1,500 nonprofit and community organizations – exceeding our fundraising goal. Combined with the Xcel Energy Foundation match to local United Way chapters, this campaign raised $5 million for our communities.

OUR PEOPLE

Champion Safety

Continuously elevating the quality and safety of the workplace is a top priority. We are considered a benchmark company for our Safety Always approach, focused on eliminating life-altering injuries through a trusted, transparent culture and the use of critical controls. All employees have "stop work authority" and are expected to keep each other, our customers and the public safe. Employees are encouraged to speak up, share experiences and learn from events to help protect themselves, their coworkers and the public.

The Board of Directors has oversight for employee and public safety through the Operations, Nuclear, Environmental and Safety committee, both of which are also tied to annual incentive compensation.

Cultivate an Inclusive, Best-in-Class Workforce

We aim to create an inclusive work culture where employees are empowered to create innovative solutions, where everyone is respected and there is a collective sense of belonging. We are building a workforce that reflects the broad range of backgrounds, experiences and perspectives within our communities and among our customers. This starts with our Board of Directors.

The Board of Directors oversees our workforce strategy, including our inclusion initiatives and employee safety and inclusion KPIs in our management annual incentive plan.

A total of 70% of annual incentive compensation was tied to safety, system reliability and inclusion metrics.

Management evaluates compensation and benefits to maintain a market-competitive, performance-based, shareholder-aligned total rewards package that supports our ability to attract, engage and retain a talented workforce.

We partner with educational and community organizations to recruit employees who reflect the communities we serve and live our values. Xcel Energy had 11,380 full-time employees and workforce demographics as of December 2024 were as follows:

	Female	Ethnically Diverse
Board of Directors	31 %	15 %
CEO direct reports	38	13
Management	25	13
Employees	23	18
New hires	40	28
Interns (hired throughout 2024)	42	40

Xcel Energy respects employees' freedom of association and their right to collectively organize. As of Dec. 31, 2024, approximately 45% of our employees (5,087) were covered by collective bargaining agreements.

We are committed to the advancement and protection of human rights, consistent with U.S. human rights laws and the general principles in the International Labour Organization Conventions.

Annual Code of Conduct training is required for all employees and the Board of Directors. We do not tolerate Code of Conduct violations or other unacceptable behaviors. We expect and offer employees multiple avenues to raise concerns or report wrong-doing and do not permit any retaliation.

OUR PERFORMANCE

Deliver a Competitive Total Return to Investors

Successful strategy execution, along with our disciplined approach to growth, operations and management of environmental, social and governance issues, positions us to continue delivering a competitive TSR.

TotalReturn-2024.jpg

We have consistently achieved our financial objectives, meeting or exceeding our initial ongoing earnings guidance range for 20 consecutive years and delivering dividend growth for 22 consecutive years.

Leading the Energy Clean Transition

Xcel Energy is committed to maintaining a safe and reliable electric and natural gas system, while leading the clean energy transition. Over the next five years, we plan to make $45 billion of capital investments to improve reliability, resiliency and sustainability. Significant investment in our transmission and distribution systems is essential to ensure resiliency and reliability for customers, we have approximately $28 billion in our 2025 - 2029 capital plan focused specifically on this.

Our sustainability commitments are summarized as follows:

Clean Energy Vision Graphic-2024.jpg

See Item 1A for risks and uncertainties related to strategic and sustainability goals and objectives.

Zero-Carbon Electricity by 2050

Xcel Energy's operating footprint includes some of the best wind and solar resources in the country, providing for higher capacity factors and lower electricity costs.

Xcel Energy's wind capacity is now over 11,000 MW, including nearly 4,500 MW of owned wind. In 2024, we completed Phase 1 of our Sherco Solar project in Minnesota. Once Phases 2 and 3 are completed in 2025 and 2026, Sherco Solar's combined capacity of 710 MW will be one of the largest solar facilities in the country and provide enough clean energy to power 150,000 homes across the upper Midwest. We have 15,000 - 29,000 MW of investment opportunity, through new and extended generation, in development across our NSP, PSCo and SPS footprint. In our base 2025 - 2029 capital investment plan, we have 3,700 MW of new and repowered wind, solar, hybrid and battery storage resources included.

Through 2024, we reduced carbon emissions from generation serving customers by an estimated 57% (from 2005 levels) and remain on track to achieve 80% carbon reduction and fully exit coal by the end of 2030.

Natural Gas Use in Buildings – Net-Zero GHG by 2050

Recognizing externalities like the pace of technology development and customer needs, Xcel Energy updated certain interim goals on the path to achieve our 2050 goal to provide net-zero natural gas service from the supply, distribution and end-use natural gas. In 2024 and early 2025, we received approvals for our modified Clean Heat Plan in Colorado and Natural Gas Innovation Plan in Minnesota, which provide starting points for this transition.

Our net-zero natural gas frameworks include the following priorities:

- Operating a safe, reliable gas system with net-zero methane gas service by 2030.
- Optimize the energy system with electrification-first approaches for new growth by leading voluntary market transformation initiatives.
- Provide customers with a portfolio of solutions to choose from, including natural gas, while ensuring we meet requirements of our regulators.

Electrification of the Transportation Sector

We are also helping reduce carbon emissions in other sectors, including transportation. Similar to our natural gas goals, we revised the interim goals to reflect market considerations for transportation to enable the charging infrastructure for 1.5 million electric vehicles across the areas we serve by 2035. By 2050, our vision remains to run all vehicles in our service area with carbon-free electricity or other clean energy. We have approved clean transportation programs and plans in Colorado, New Mexico, Minnesota and Wisconsin.

Wildfire Resiliency and Mitigation

Protecting our customers and our system from the threats of extreme weather is a top priority for Xcel Energy. In 2024, we filed an updated Wildfire Mitigation Plan in Colorado and our Resiliency Plan in Texas that integrates industry experience, incorporates evolving risk assessment methodologies, adds new technology and expands the scope, pace and scale of our programs to reduce wildfire risk. We also issued wildfire mitigation plans for each of our other states in 2024.

In 2024, we implemented the capability to deliver enhanced, wildfire safety operations and conduct proactive public safety power shutoffs across our entire system. We accelerated pole inspections and replacements on our system and expanded visual coverage of high-risk areas with our PanoAI camera system. We also deployed Technosylva's advanced risk modelling system enterprise-wide.

Finally, we are working at both a state and federal level on legislation to enhance the safety of our communities from evolving extreme weather risks while protecting the financial integrity of companies like Xcel Energy.

Utility Subsidiaries

NSP-Minnesota

Electric customers	1.6 million
Natural gas customers	0.6 million
Total assets	$27.5 billion
Rate Base (estimated)	$17.4 billion
GAAP ROE	9.07%
Ongoing ROE	9.46%
Electric generating capacity (owned)	8,623 MW
Gas storage capacity	16.9 Bcf
Electric transmission lines (conductor miles)	34,000 miles
Electric distribution lines (conductor miles)	87,000 miles
Natural gas transmission lines	78 miles
Natural gas distribution lines	11,000 miles

NSP-M-map-185-blk.jpg

NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSP-Wisconsin

Electric customers	0.3 million
Natural gas customers	0.1 million
Total assets	$4.1 billion
Rate Base (estimated)	$2.7 billion
GAAP ROE	8.98%
Electric generating capacity (owned)	500 MW
Gas storage capacity	4.3 Bcf
Electric transmission lines (conductor miles)	12,000 miles
Electric distribution lines (conductor miles)	28,000 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	3,000 miles

NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, purchases, transmits, distributes and sells electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

PSCo

Electric customers	1.6 million
Natural gas customers	1.5 million
Total assets	$26.6 billion
Rate Base (estimated)	$19.3 billion
GAAP ROE	7.63%
Electric generating capacity (owned)	6,203 MW
Gas storage capacity	32.1 Bcf
Electric transmission lines (conductor miles)	25,000 miles
Electric distribution lines (conductor miles)	82,000 miles
Natural gas transmission lines	2,000 miles
Natural gas distribution lines	24,000 miles

PSCo-185-blk-map-tilt.jpg

PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

SPS

Electric customers	0.4 million
Total assets	$10.8 billion
Rate Base (estimated)	$7.6 billion
GAAP ROE	9.57%
Electric generating capacity (owned)	5,100 MW
Electric transmission lines (conductor miles)	41,000 miles
Electric distribution lines (conductor miles)	25,000 miles

SPS-map-185-blk.jpg

SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

Operations Overview

Utility operations are generally conducted as either electric or gas utilities in our four utility subsidiaries.

Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities across all four utility subsidiaries. Xcel Energy had electric sales volume of 112,273 (millions of KWh), 3.9 million customers and electric revenues of $11,147 million for 2024.

Electric Operations (percentage of total)	Sales Volume	Number of Customers	Revenues
Residential	23 %	86 %	32 %
C&I	59	12	49
Other	18	2	19

Retail Sales/Revenue Statistics [(a)]

	2024	2023
KWh sales per retail customer	23,908	23,939
Revenue per retail customer	$ 2,357	$ 2,464
Residential revenue per KWh	13.82 ¢	13.80 ¢
C&I revenue per KWh	8.24 ¢	8.82 ¢
Total retail revenue per KWh	9.86 ¢	10.29 ¢

(a) See Note 6 to the consolidated financial statements for further information.

Owned and Purchased Energy Generation — 2024

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Electric Energy Sources

Total electric energy generation by source for the year ended Dec. 31:

Full page trimmed V2.jpg

Carbon-Free

Xcel Energy's carbon-free energy portfolio includes wind, nuclear, hydroelectric, biomass and solar power from both owned generation facilities and PPAs. Carbon-free percentages will vary year-over-year based on system additions, commodity costs, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Wind

Wind capacity is shown as net maximum capacity. Net maximum capacity is attainable only when wind conditions are sufficiently available.

Owned — Owned and operated wind farms with corresponding capacity:

	2024		2023	
Utility Subsidiary	**Wind Farms**	**Capacity (MW)**	**Wind Farms**	**Capacity (MW)**
NSP System	17	2,445	17	2,444
PSCo	2	1,059	2	1,059
SPS	2	985	2	985
Total	21	4,489	21	4,488

PPAs — Number of PPAs with capacity range:

	2024		2023	
Utility Subsidiary	**PPAs**	**Range (MW)**	**PPAs**	**Range (MW)**
NSP System	116	1 — 206	120	1 — 206
PSCo	16	23 — 301	17	23 — 301
SPS	16	1 — 250	16	1 — 250

PPAs — Contracted wind capacity (MW) for PPAs:

Utility Subsidiary	2024	2023
NSP System	2,061	2,066
PSCo	2,996	3,026
SPS	1,562	1,562

Average Cost — Average cost per MWh of wind energy from owned generation and existing PPAs:

Type	Utility Subsidiary	2024	2023
Owned Generation [(a)]	NSP System	$ 7	$ 7
PPA	NSP System	32	33
Owned Generation [(a)]	PSCo	4	7
PPA	PSCo	43	42
Owned Generation [(a)]	SPS	1	6
PPA	SPS	28	26

(a) Includes the impact of PTCs.

Xcel Energy currently has approximately 1,900 MW of owned wind under development or being repowered. This includes 350 MW of approved repowering projects at the NSP System estimated to be completed in 2025. The Company anticipates approximately 1,550 MW at PSCo as part of the Colorado Resource Plan and anticipates approval of an additional 300 MW of PPAs as part of the Colorado Resource Plan, additions are expected to be placed in service between 2026 - 2028.

Additionally, the NSP System anticipates 3,200 MW to be placed in service by 2030, as part of the recently approved Upper Midwest Resource Plan. The RFP process will start in 2025.

Solar

Owned — Owned and operated solar projects with corresponding capacity:

	2024		2023	
Utility Subsidiary	**Solar Projects**	**Capacity (MW)**	**Solar Projects**	**Capacity (MW)**
NSP System [(a)]	1	223	—	—

(a) NSP-Minnesota placed in service Sherco Solar 1 in the fourth quarter of 2024. Average cost per MWh will be available after a full year of operations.

PPAs — Solar PPAs capacity by type:

Type	Utility Subsidiary	Capacity (MW)
Distributed Generation	NSP System	1,461
Utility-Scale	NSP System	349
Distributed Generation	PSCo	1,031
Utility-Scale [(a)]	PSCo	1,530
Distributed Generation	SPS	30
Utility-Scale	SPS	192
Total		4,593

(a) Includes battery storage capacity of 225 MW.

Average Cost (PPAs) — Average cost per MWh of solar energy under existing distributed and utility-scale generation PPAs:

Utility Subsidiary	2024	2023
NSP System	$ 100	$ 90
PSCo	31	34
SPS	68	67

Solar Development — Xcel Energy currently has approximately 2,700 MW of owned and PPA solar under development. For the NSP System, this includes 500 MW of solar approved at the Sherco site which are expected to be placed in service in 2025 and 2026. Additionally, various PPAs totaling approximately 105 MW are expected to be completed throughout 2025. Incremental to this amount is 400 MW anticipated as part of the Upper Midwest Resource Plan, to be placed in service by 2030.

PSCo anticipates development of approximately 1,700 MW of solar generation resources (650 MW company owned, 1,050 MW as PPAs) as part of the Colorado Resource Plan. Colorado Resource Plan additions are expected to be placed in service between 2026 - 2028.

For SPS, approximately 450 MW of solar and storage are expected to be placed in service in 2026 and 2027.

Nuclear

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2024 net summer dependable capacity that safely and reliably generates carbon free electricity for the NSP System. Xcel Energy secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. We use varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost — Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal):

Utility Subsidiary	Nuclear	
NSP System	**Cost**	**Percent**
2024	$ 0.83	43 %
2023	0.76	50

Other — Xcel Energy's other carbon-free energy portfolio includes hydro from owned generating facilities.

The NSP System anticipates development of approximately 300 MW of storage capacity at the Sherco site, expected to be placed in service in 2027. Additionally, 600 MW of stand-alone storage are expected to be added as part of the Upper Midwest Resource Plan, to be placed in service by 2030.

PSCo anticipates development of approximately 1,850 MW of storage capacity (400 MW company owned, 1,450 MW as PPAs) as part of the Colorado Resource Plan. Colorado Resource Plan additions are expected to be placed in service between 2026 - 2028.

See Item 2 — Properties for further information.

Fossil Fuel

Xcel Energy's fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

Coal

Xcel Energy owned and operated coal units with approximately 5,500 MW of total 2024 net summer dependable capacity, which provided 15% of Xcel Energy's energy mix in 2024. This amount includes the coal units Harrington Units 1-3, which are in the process of being converted to natural gas (net summer dependable capacity of 1,018 MW) and approximately 100 MW derived from RDF and wood fuel sources.

Xcel Energy has plans to retire or convert to natural gas all of its existing coal generation by the end of 2030. Approved early coal plant retirements:

Year	Utility Subsidiary	Plant Unit	Capacity (MW)
2025	PSCo	Comanche 2	330
2025	PSCo	Craig 1	42 [(a)]
2025	PSCo	Pawnee [(b)]	505
2026	NSP-Minnesota	Sherco 1	680
2027	PSCo	Hayden 2	98 [(a)]
2028	PSCo	Hayden 1	135 [(a)]
2028	PSCo	Craig 2	40 [(a)]
2028	NSP-Minnesota	A.S. King	511
2028	SPS	Tolk 1	532
2028	SPS	Tolk 2	535
2030	NSP-Minnesota	Sherco 3	517 [(a)]
2030	PSCo	Comanche 3	500 [(a)]

(a) Based on Xcel Energy's ownership interest.
(b) Reflects planned conversion from coal to natural gas.

Coal Fuel Cost — Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of fuel requirements (nuclear, natural gas and coal):

Utility Subsidiary	Coal [(a)]	
	Cost	**Percent**
NSP System		
2024	$ 2.24	22 %
2023	2.43	29
PSCo		
2024	1.91	44
2023	1.57	54
SPS		
2024	2.87	34
2023	2.73	48

(a) Includes RDF and wood for the NSP System.

Natural Gas

Xcel Energy has 22 natural gas plants with approximately 8,000 MW of total 2024 net summer dependable capacity, which provided 33% of Xcel Energy's mix in 2024.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost — Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal):

Utility Subsidiary	Natural Gas	
	Cost	**Percent**
NSP System		
2024	$ 1.94	35 %
2023	3.91	21
PSCo		
2024	2.77	56
2023	3.06	46
SPS		
2024	0.94	66
2023	2.35	52

The NSP System anticipates the development of 700 MW of company owned natural gas generation expected to be placed in service between 2025 - 2028.

PSCo anticipates development of approximately 450 MW of company owned natural gas generation, as part of the Colorado Resource Plan to help ensure resiliency and reliability. Colorado Resource Plan additions are expected to be placed in service between 2026 - 2028.

In 2024, SPS converted a total of 339 MW from coal to natural gas related to the Harrington station coal to natural gas repowering project. In January 2025, an additional 341 MW has been converted to natural gas. Through 2025, SPS expects to convert a final 338 MW to natural gas.

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

	2024		2023	
Utility Subsidiary	**MW**	**Date**	**MW**	**Date**
NSP System	8,822	Aug. 26	9,231	Aug. 23
PSCo	7,084	Aug. 1	6,909	July 24
SPS	4,437	Aug. 19	4,372	Aug. 17

Transmission

Transmission lines deliver electricity at high voltages and over long distances from power sources to substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. Xcel Energy owns approximately 111,000 conductor miles of transmission lines across its service territory.

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. Xcel Energy has a vast distribution network, owning and operating approximately 221,000 conductor miles of distribution lines across our eight-state service territory.

See Item 2 - Properties for further information.

Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end-use residential, C&I and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 387,513 (thousands of MMBtu), 2.2 million customers and natural gas revenues of $2,230 million for 2024.

Natural Gas (percentage of total)	Deliveries	Number of Customers	Revenues
Residential	35 %	92 %	58 %
C&I	24	8	29
Transportation and other	41	<1	13

Sales/Revenue Statistics [(a)]

	2024	2023
MMBtu sales per retail customer	105	115
Revenue per retail customer	$ 896	$ 1,113
Residential revenue per MMBtu	9.48	10.54
C&I revenue per MMBtu	7.04	8.48
Transportation and other revenue per MMBtu	1.10	1.01

(a) See Note 6 to the consolidated financial statements for further information.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible.

Maximum daily output (firm and interruptible) and occurrence date:

	2024		2023	
Utility Subsidiary	**MMBtu**	**Date**	**MMBtu**	**Date**
NSP-Minnesota	841,164	Jan. 19	753,642	Feb. 3
NSP-Wisconsin	163,246	Jan.17	158,029	Jan. 30
PSCo	2,357,931	Jan.15	2,190,155	Jan. 30

Natural Gas Supply and Cost

Xcel Energy seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increases flexibility and decreases interruption, financial risks and customer rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their states' commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

Utility Subsidiary	2024	2023
NSP-Minnesota	$ 3.97	$ 5.31
NSP-Wisconsin	3.77	5.26
PSCo	3.36	4.91

NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery.

General

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of fluctuating energy or commodity prices, pandemics, terrorist activity, war or the threat of war. We could experience a material impact to our results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates or inflation.

Seasonality

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 warmer in the winter and cooler in the summer. Sales true-up and decoupling mechanisms mitigate the impacts of weather in certain jurisdictions.

Competition

Xcel Energy is subject to public policies that promote competition and development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them in most jurisdictions.

Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to Xcel Energy's electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energy's wholesale customers can purchase energy from other generation resources and transmission services from other service providers to serve their native load.

FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities.

FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear.

Xcel Energy Inc.'s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization. No municipalization activities are occurring presently.

While each utility subsidiary faces these challenges, Xcel Energy believes their rates and services are competitive with alternatives currently available.

Governmental Regulations

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain Xcel Energy activities require registrations, permits, licenses, inspections and approvals from these agencies.

Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements.

However, it is not possible to determine what additional facilities or modifications to existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of historic and current operating sites and other waste treatment, storage and disposal sites.

There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs. However, costs to comply with past environmental regulations have largely been recoverable through rates.

Emerging Environmental Regulation

Clean Air Act

Power Plant Greenhouse Gas Regulations — In April 2024, the EPA published final rules addressing control of CO_2 emissions from the power sector. The rules regulate new natural gas generating units and emission guidelines for existing coal and certain natural gas generation. The rules create subcategories of coal units based on planned retirement date and subcategories of natural gas combustion turbines and combined cycle units based on utilization. The CO_2 control requirements vary by subcategory. Based on current estimates and assumptions, Xcel Energy has determined that due to scheduled plant retirements, there is minimal financial or operational impact associated with these requirements and believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

Waste-to-Energy Air Regulations — In January 2024, the EPA proposed air regulations addressing new and existing large municipal waste combustors. The proposed rules lower current emission standards for certain pollutants and would require installation of new pollution controls and/or more intense use of existing pollution controls at French Island Generating Station, Red Wing Generating Plant and Wilmarth Generating Plant. Until final rules are issued, it is not certain what the impact will be on Xcel Energy. Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

Emerging Contaminants of Concern

PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. Xcel Energy does not manufacture PFAS, but because PFAS are so ubiquitous in products and the environment, it may impact our operations.

In June 2024, the EPA finalized a rule that designated certain PFAS as hazardous substances under CERCLA. In July 2024, the EPA finalized another rule that set enforceable drinking water standards for certain PFAS.

Potential costs for these rules and any additional proposed regulations related to PFAS are uncertain and will be determined on a site specific basis where applicable. If costs are incurred, Xcel Energy believes the costs will be recoverable through rates based on prior state commission practices.

Effluent Limitation Guidelines

In April 2024, the EPA published final rules under the Clean Water Act, setting Effluent Limitations Guidelines and Standards for steam generating coal plants. This rule establishes more stringent wastewater discharge standards for bottom ash transport water, flue-gas desulfurization wastewater, and combustion residuals leachate from steam electric power plants, particularly coal-fired power plants. Based on current estimates and assumptions, Xcel Energy has determined that there is minimal financial or operational impact associated with these requirements and that any costs would be recoverable through rates based on prior state commission practices.

Environmental Costs

Environmental costs include amounts for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions.

Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste and depreciation of previously incurred capital expenditures for environmental improvements were approximately:

- $290 million in 2024.
- $275 million in 2023.
- $365 million in 2022.

Average annual expense of approximately $330 million from 2025 – 2029 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be recovered through rates may fluctuate.

Capital expenditures for environmental improvements were approximately:

- $25 million in 2024.
- $20 million in 2023.
- $20 million in 2022.

Certain previously collected nuclear storage costs for the federal nuclear waste program are reimbursed to customers by the federal government as a result of a settlement we pursued regarding the government's failure to deliver a disposal program. Installments received are reimbursed to customers as approved by the MPUC and other state regulators.

Other

Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material.

Capital Spending and Financing

See Item 7 for discussion of capital expenditures and funding sources.

Information about our Executive Officers [(a)]

Name	Age	Current and Recent Positions	Time in Position
Robert C. Frenzel	54	Chairman of the Board of Directors, Xcel Energy Inc.	December 2021 — Present
		President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2021 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS	August 2021 — Present
		President and Chief Operating Officer, Xcel Energy Inc.	March 2020 — August 2021
		Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 — March 2020
Robert Berntsen	55	Executive Vice President, Chief Legal and Compliance Officer, Xcel Energy Inc.	May 2024 — Present
		Senior Vice President, General Counsel, BHE Renewables, LLC, a development and commercial management of renewable energy projects company	December 2020 — May 2024
		Senior Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer, MidAmerican Energy Company, a regulated electric and gas utility	March 2015 — December 2020
Patricia Correa	51	Senior Vice President, Chief Human Resources Officer, Xcel Energy Inc.	February 2022 — Present
		Senior Vice President, Human Resources, Eaton Corporation, a power management company	July 2019 — January 2022
Timothy O'Connor	65	Executive Vice President, Chief Operations Officer, Xcel Energy Inc.	August 2021 — Present
		Executive Vice President, Chief Generation Officer, Xcel Energy Inc.	March 2020 — August 2021
		Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc	February 2013 — March 2020
Amanda Rome	44	Executive Vice President, Group President, Utilities, and Chief Customer Officer, Xcel Energy Inc.	October 2023 — Present
		Interim General Counsel, Xcel Energy Inc.	January 2024 — May 2024
		Executive Vice President, Chief Legal and Compliance Officer, Xcel Energy Inc.	June 2022 — October 2023
		Executive Vice President, General Counsel, Xcel Energy Inc.	June 2020 — June 2022
		Vice President and Deputy General Counsel, Xcel Energy Services Inc.	October 2019 — June 2020
Brian J. Van Abel	43	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	March 2020 — Present
		Senior Vice President, Finance and Corporate Development, Xcel Energy Services Inc.	September 2018 — March 2020

[(a)] No family relationships exist between any of the executive officers or directors.

ITEM 1A — RISK FACTORS

Xcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC.

While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Oversight of Risk and Related Processes

The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors' committees have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Xcel Energy maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our Code of Conduct and compliance policies, operation of formal risk management structures and overall business management. Xcel Energy further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls.

Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing Xcel Energy's strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental, safety and security risks.

The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of Xcel Energy. The Board of Directors assigns oversight of critical risks to each of its four committees to confirm these risks are well understood and given appropriate focus.

The Audit Committee is responsible for reviewing the adequacy of the committees' risk oversight and affirming appropriate aggregate oversight occurs. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate.

Emerging risks are considered and assigned as appropriate during the annual Board of Directors and committee evaluation process, resulting in updates to the committee charters and annual work plans. Additionally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric generation/transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages.

These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses to customers, the public, employees or third-party contractors. We maintain insurance against most, but not all, of these risks and losses.

The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential reputational impact.

Other uncertainties and risks inherent in operating and maintaining Xcel Energy's facilities include, but are not limited to:

- Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned.
- Failures in the availability, acquisition or transportation of fuel or other supplies.
- Impact of adverse weather conditions and natural disasters, including, wildfires, tornadoes, avalanches, icing events, floods, high winds, droughts and the availability or changes to wind patterns
- Performance below expected or contracted levels of output or efficiency.
- Availability of replacement or new equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Inability to identify, manage properly or mitigate equipment defects.
- Use of new or unproven technology.
- Inability to use information effectively given the rapidly increasing volume of data.
- Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources.
- Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes.
- Increased costs due to aging infrastructure.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Xcel Energy's long-term resource plan is dependent on our ability to obtain required approvals (including regulatory approval in jurisdictions where Xcel Energy operates), develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning processes and our asset lives are subject to risk. The utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation). Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments.

The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. New data centers and crypto mining facilities could generate significant increase in demand. Higher electric demand may require us to adopt new technologies and make significant generation, transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We require inputs such as coal, natural gas, uranium and water. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Our utilities are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules.

Our products contain components that are globally sourced from suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact operations and project plans for Xcel Energy and our customers. Such impacts could include timing of projects and the potential for project cancellation. Failure to adhere to project budgets and timelines could adversely impact our results of operations, financial condition or cash flows.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events. Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes over the long-term may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires, snow, ice storms or extreme temperatures (high heating/cooling days) occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service and result in more frequent service interruptions. Periods of extreme temperatures could also impact our ability to meet demand.

Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants that require water or increase the cost for energy.

Adverse events may result in increased insurance costs and/or decreased insurance availability. We may not recover all costs related to mitigating these physical and financial risks.

Our utilities have physical and financial risks associated with wildfires.

In recent years, wildfires have impacted the utility industry. More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. Also, the expansion of the wildland urban interface increases the wildfire risk to surrounding communities and Xcel Energy's electric and natural gas infrastructure. Wildfires could jeopardize Xcel Energy's electric and gas infrastructure and third-party property and result in temporary power outages or shortages in our service territories.

We have programs in place to mitigate the physical and financial risks associated with wildfires; however, Xcel Energy's wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related losses. Wildfires can occur even when Xcel Energy follows its procedures and implements its wildfire mitigation initiatives.

Other potential risks associated with wildfires and other climate events include the inability to secure sufficient insurance coverage, increased costs of insurance, or ability for insurers to meet their obligations, regulatory recovery risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts could potentially exceed our coverage and negatively impact our results of operations, financial condition or cash flows.

We are subject to commodity risks and other risks associated with energy markets and energy production.

A significant increase in fuel costs could cause a decline in customer demand, adverse regulatory outcomes and an increase in bad debt expense which may have a material impact on our results of operations. Despite existing fuel cost recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity.

A significant disruption in supply could cause us to seek alternatives at potentially higher costs. Additionally, supply shortages may not be fully resolved, which negatively impacts our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments negatively impacts our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk.

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends.

Public perception often does not distinguish between pass through commodity costs and base rates. High commodity prices that are passed through to customer bills could impact our ability to recover costs for other improvements and operations.

Due to the uncertainty involved in price movements and potential deviation from historical pricing, Xcel Energy is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations.

In addition, Xcel Energy cannot fully assure that its controls will be effective against all potential risks. If such programs and procedures are not effective, Xcel Energy's results of operations, financial condition or cash flows could be materially impacted.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

The competition for talent has become increasingly prevalent, and we have experienced increased employee turnover due to the condition of the labor market and decisions related to strategic workforce planning. In addition, specialized knowledge and skills are required for many of our positions, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate.

Failure to hire, adequately train replacement employees, transfer knowledge/expertise or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

Our businesses have collective bargaining agreements with labor unions. Failure to renew or renegotiate these contracts could lead to labor disruptions, including strikes or boycotts. Such disruptions or any negotiated wage or benefit increases could have a material adverse impact to our results of operations, financial condition or cash flows.

National unionization efforts could affect our business, as an increase in unionized workers could challenge our operational efficiency and increase costs.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance and safety standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, regulatory recovery and our reputation and could introduce financial risk or risks of fines.

Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation.

We are exposed to risk of employee or third-party contractor fraud or misconduct. All employees and members of the Board of Directors are subject to compliance with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to compliance with our Supplier Code of Conduct.

Xcel Energy does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota has two nuclear generation plants, Prairie Island and Monticello. Risks of nuclear generation include:

- Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal.
- Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor.
- Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the INPO reviews NSP-Minnesota's nuclear operations. Compliance with the INPO's recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If a nuclear incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase NSP-Minnesota's compliance costs.

Financial Risks

Our profitability depends on the ability of our utility subsidiaries to recover their costs, and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on capital investment. Our rates are generally regulated and are based on an analysis of the utility's costs incurred in a test year. The utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery.

Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair the ability of our utility subsidiaries to recover costs historically collected from customers, or these subsidiaries could exceed caps on capital costs required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

Higher than expected inflation, shortages of skilled labor, tariffs or federal policies may increase costs of construction and operations. Also, rising fuel costs could increase prices to consumers, all of which could increase the risk that our utility subsidiaries will not be able to fully recover their costs from their customers.

Adverse regulatory rulings (including changes in recovery mechanisms) or the imposition of additional regulations could negatively impact our results of operations, financial condition or cash flows.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

Our credit ratings are subject to change, and our credit ratings may be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, use of historic test years, elimination of riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios, impacts of tax policy and unfavorable litigation outcomes may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade. The credit rating agencies may change their assessment or our regulatory or business risk, such as with the increase of climate events, which could negatively impact our credit ratings.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission NSP-Minnesota's nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in our cash flows and liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and unemployment rates.

Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we may incur losses. This could be particularly impactful for long-lead time equipment contracts that require significant deposits and milestone payments, for items that may be difficult to procure elsewhere in the event of non-performance.

Xcel Energy may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., MISO, SPP, ERCOT and California ISO), in which any credit losses are socialized to all market participants.

We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future.

Also, the payout of a significant percentage of pension plan liabilities in a single year, due to high numbers of retirements or employees leaving, would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

Investments in our subsidiaries are our primary assets. Substantially all our operations are conducted by our subsidiaries. Consequently, our operating cash flows and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends.

Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets.

If the utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected. Our utility subsidiaries are regulated by state utility commissions, which possess broad powers to prioritize that the needs of the utility customers are met. We may be negatively impacted by the actions of state commissions that limit the payment of dividends by our utility subsidiaries.

Federal tax law may significantly impact our business.

Our utility subsidiaries collect estimated federal, state and local tax payments through their regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value/availability of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies, such as tax normalization, may impact our ability to economically deliver certain types of resources relative to market prices. Changes to the availability of tax credit transferability could impact our cash flows and the cost of certain types of resources.

Macroeconomic Risks

Economic conditions impact our business.

Xcel Energy's operations are affected by economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by recessionary factors, rising interest rates, inflation, the impacts of federal policy and insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills, which could lead to additional bad debt expense.

Our utility subsidiaries face competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital-intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

The oil and gas industry represents our largest C&I customer base. Oil and natural gas prices are sensitive to market risk factors which may impact demand.

We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows.

Health epidemics impact countries, communities, supply chains and markets. Uncertainty continues to exist regarding epidemics; the duration and magnitude of business restrictions including shutdowns (domestically and globally); the potential impact on the workforce including shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; impacts on the transportation of goods, and the generalized impact on the economy.

We cannot ultimately predict whether an epidemic will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact on the health of our employees, our supply chain or our ability to recover higher costs associated with managing an outbreak.

Operations could be impacted by war, terrorism or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows.

The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storms, temperature extremes, wildfires, widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption.

In addition, major catastrophic events throughout the world may disrupt our business. While we have business continuity plans in place, our ability to recover may be prolonged due to the type and extent of the event. Xcel Energy participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to connect, restore and reliably serve our customers.

A major disruption could result in a significant decrease in revenues, additional costs to repair assets, and an adverse impact on the cost and availability of insurance, which could have a material impact on our results of operations, financial condition or cash flows.

A cybersecurity incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including Company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Xcel Energy's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cybersecurity incidents, including those caused by human error.

The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cybersecurity incidents from international activist organizations, other countries and individuals. We expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack affecting us or our vendors has had a material impact on our business or results of operations.

Cybersecurity incidents could harm our businesses by limiting our generation, transmission and distribution capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Xcel Energy's generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cybersecurity incident on the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Generative Artificial Intelligence, such as large language models like ChatGPT, present a range of challenges and potential risks as we consider impacts to the business. These challenges involve navigating the complexities of creating and deploying AI models that generate content autonomously. Data privacy, legal concerns, and security issues are all risks as this technology continues to be adopted.

Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cybersecurity threats or subsequent related actions. Cybersecurity incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cybersecurity incidents, including asset failure or unauthorized access to assets or information.

A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cybersecurity threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

While the Company maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damages experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Public Policy Risks

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. FERC can impose penalties of up to $1.5 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cybersecurity or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

The continued use of natural gas for both power generation and gas distribution have increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for both power generation and heating, which could impact our ability to reliably and affordably serve our customers.

In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service.

Environmental Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations.

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius. Although the United States has withdrawn from the Paris Agreement, many states and localities continue to pursue their own climate policies which could result in future additional GHG reductions.

The steps Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation and retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination.

Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or O&M costs incurred to comply with the requirements. Additionally, the impact of environmental laws and regulations may impact the economic health of consumers through higher prices of energy and purchased goods.

While we establish strategies and expectations related to climate change and other environmental matters, our ability to achieve any such strategies or expectations is subject to numerous factors and conditions, many of which are outside of our control. Examples of such factors include, but are not limited to, evolving legal, regulatory, and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets. Failures or delays (whether actual or perceived) in achieving our strategies or expectations related to climate change and other environmental matters could adversely affect our business, operations, and reputation, and increase risk of litigation.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 1C — CYBERSECURITY

As described in Item 1A – Risk Factors, Xcel Energy operates in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure, as such, our business is subject to the risk of interruption by cybersecurity incidents that range from attacks common to most industries, such as phishing and denial-of-service, to attacks from more sophisticated adversaries, including nation state actors, that target the critical infrastructure used in the operation of our business.

The Company has a security risk program in place to identify, assess, manage and report material risks from cybersecurity incidents. As a utility provider, Xcel Energy complies with reliability standards imposed by NERC, including critical infrastructure protection standards related to both cybersecurity and physical security. These standards imposed by NERC, in alignment with the NIST Cybersecurity Framework, are the basis for which Xcel Energy has designed the cybersecurity control framework within its security risk program.

Annually, as part of Xcel Energy's enterprise risk program, an integrated cybersecurity risk identification and assessment is completed across Xcel Energy's business, including generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets as well as information processed in our systems (including systems hosted by third parties) that could be affected by cybersecurity incidents. This analysis includes the impact, likelihood, timeframe and controllability of cybersecurity risks and is presented to the Board of Directors. Management monitors and reviews the results of this analysis, integrating them into the enterprise risk assessment processes and implements appropriate mitigating actions as needed.

Xcel Energy's cybersecurity policies, standards, practices, annual cybersecurity training content and readiness are regularly assessed by third-party consultants. These partners are engaged to perform independent penetration testing and other security related services to assist in the prevention, detection, monitoring, mitigation and remediation of cybersecurity incidents and risks. The results of these assessments are communicated to management and the Board of Directors by the Chief Security Officer.

Xcel Energy employs a comprehensive risk based approach to assess the magnitude and significance of a vendor's risk to the Company. Certain third-party service providers are subject to vendor security risk assessments at the time of integration, contract execution/renewal, and upon detection of any increase in risk profile. Xcel Energy uses a variety of inputs in such risk assessments, including information supplied by providers and third parties (including information analysis centers that share daily threat intelligence and improve organizational agility associated with management of cybersecurity risks). In addition, the Company requires certain third-party service providers to meet appropriate security requirements, controls and responsibilities. The Company deploys periodic monitoring activities to assess compliance with our cybersecurity control framework and investigates security incidents that have impacted our third-party service providers as appropriate.

Management has assigned responsibility for the security risk program to the Chief Security Officer who has multiple years of experience in the Defense Industrial Base. The Chief Security Officer is informed about and monitors prevention, detection, mitigation and remediation efforts through a team of security professionals, many of whom are Certified Information Systems Security Professionals, Certified Information Security Managers or have received other cybersecurity certifications. The team has extensive experience selecting, deploying and operating cybersecurity technologies, initiatives and processes that aid in preventing, remediating and mitigating known and unknown security threats.

The Chief Security Officer or members of management brief the Board on routine and regular cybersecurity risk and threat updates, typically on an annual basis. In the event of a significant threat or incident, management and the Chief Security Officer leverage Xcel Energy's incident response processes to assess impacts and resolve incidents. When a significant cybersecurity incident occurs, management communicates with the Board of Directors and relevant committees.

The Board of Directors oversees the risks associated with cybersecurity and the physical security of our assets, with information security matters being discussed at board meetings as well as at the ONES and Audit Committee meetings throughout the year.

While the ONES Committee has primary committee responsibility for cybersecurity due to the operational issues involved, the Board of Directors has determined that the topic is of sufficient importance to warrant this comprehensive oversight approach. Augmenting such oversight efforts, the enterprise has the ability to notify and update the Board of Directors in the event of a possible crisis situation.

Cybersecurity risks are a part of Xcel Energy's normal course of business. To date, no cybersecurity incident or attack affecting us or our vendors has had a material impact on our business or results of operations. As of Feb. 27, 2025 there have been no material cybersecurity incidents to report.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of the utility subsidiaries is subject to the lien of their respective first mortgage bond indentures.

NSP-Minnesota

Station, Location and Unit at Dec. 31, 2024	Fuel	Installed	MW [(a)]
Steam:			
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511
Sherco-Becker, MN			
Unit 1	Coal	1976	680
Unit 3	Coal	1987	517 [(b)]
Monticello, MN, 1 Unit	Nuclear	1971	617
Prairie Island-Welch, MN			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units	Wood/RDF	Various	36 [(c)]
Combustion Turbine:			
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	343
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	491
Blue Lake-Shakopee, MN, 6 Units	Natural Gas/Oil	1974 - 2005	454
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 8 Units	Natural Gas/ Oil	1972 - 1996	276
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Hydro:			
Hennepin Island-Minneapolis, MN 5 Units	Hydro	1954-1955	6
Wind:			
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200 [(d)]
Blazing Star 2-Lincoln County, MN, 100 Units	Wind	2021	200 [(d)]
Border-Rolette County, ND, 75 Units	Wind	2015	148 [(d)]
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26 [(d)]
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190 [(d)]
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192 [(d)]
Dakota Range, SD, 72 Units	Wind	2022	298 [(d)]
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150 [(d)]
Freeborn-Freeborn County, MN, 100 Units	Wind	2021	200 [(d)]
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	100 [(d)]
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43 [(d)]
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99 [(d)]
Mower-Mower County, MN, 43 Units	Wind	2021	91 [(d)]
Nobles-Nobles County, MN, 133 Units	Wind	2010	200 [(d)]
Northern Wind-Murray County, MN, 37 Units	Wind	2023	92 [(d)]
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 [(d)]
Rock Aetna-Murray County, MN, 8 Units	Wind	2022	20 [(d)]
Solar:			
Sherco Solar 1-Becker, MN, 63 units	Solar	2024	223
		Total	8,623

(a) Summer 2024 net dependable capacity. Wind and solar is presented as net maximum capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) RDF is made from municipal solid waste.
(d) Net maximum capacity is attainable only when wind conditions are sufficiently available. Typical average capacity factors are 35-50% for wind facilities. For the year ended Dec. 31, 2024, NSP-Minnesota's wind facilities had a weighted-average capacity factor of 46%.

NSP-Wisconsin

Station, Location and Unit at Dec. 31, 2024	Fuel	Installed	MW [(a)]
Steam:			
Bay Front-Ashland, WI, 2 Units	Wood/Natural Gas	1948 - 1956	41
French Island-La Crosse, WI, 2 Units	Wood/RDF	1940 - 1948	16 [(b)]
Combustion Turbine:			
French Island-La Crosse, WI, 2 Units	Oil	1974	119
Wheaton-Eau Claire, WI, 4 Units	Natural Gas/Oil	1973	189 [(c)]
Hydro:			
Various locations, 62 Units	Hydro	Various	135
		Total	500

(a) Summer 2024 net dependable capacity.
(b) RDF is made from municipal solid waste.
(c) Retired unit in 2024.

PSCo

Station, Location and Unit at Dec. 31, 2024	Fuel	Installed	MW [(a)]
Steam:			
Comanche-Pueblo, CO			
Unit 2	Coal	1975	330
Unit 3	Coal	2010	500 [(b)]
Craig-Craig, CO, 2 Units	Coal	1979 - 1980	82 [(c)]
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233 [(d)]
Pawnee-Brush, CO, 1 Unit	Coal	1981	505
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310
Combustion Turbine:			
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	1,022
Manchief-Brush, CO, 2 Units	Natural Gas	2000	250
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	592
Valmont-Boulder, CO, 3 units	Natural Gas	1973 - 2001	119
Various locations, 5 Units	Natural Gas	Various	128
Hydro:			
Cabin Creek-Georgetown, CO			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 6 Units	Hydro	Various	23
Wind:			
Rush Creek, CO, 300 units	Wind	2018	582 [(e)]
Cheyenne Ridge, CO, 229 units	Wind	2020	477 [(e)]
		Total	6,203

(a) Summer 2024 net dependable capacity. Wind is presented as net maximum capacity.
(b) Based on PSCo's ownership of 67%.
(c) Based on PSCo's ownership of 10%.
(d) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(e) Net maximum capacity is attainable only when wind conditions are sufficiently available. Typical average capacity factors are 35-50% for wind facilities. For the year ended Dec. 31, 2024, PSCo's wind facilities had a weighted-average capacity factor of 44%.

SPS

Station, Location and Unit at Dec. 31, 2024	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 1 Unit	Natural Gas	1957 - 1965	183
Harrington-Amarillo, TX 1 Unit	Natural Gas	2024	339 [(b)]
Harrington-Amarillo, TX 2 Units	Coal	1976 - 1980	679 [(b)]
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 1 Unit	Natural Gas	1952 - 1964	190
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	207
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	478 [(c)]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [(c)]
		Total	5,100

(a) Summer 2024 net dependable capacity. Wind is presented as net maximum capacity.
(b) Harrington coal plant units 1-3 were retired in December 2024. Unit 2 was repowered to natural gas in the fourth quarter of 2024. Units 1 and 3 are also being repowered to natural gas in 2025, with Unit 1 having completed conversion in January and Unit 3 expected to be completed in the summer.
(c) Net maximum capacity is attainable only when wind conditions are sufficiently available. Typical average capacity factors are 35-50% for wind facilities. For the year ended Dec. 31, 2024 SPS' wind facilities had a weighted-average capacity factor of 50%.

Electric utility overhead and underground transmission and distribution lines at Dec. 31, 2024:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Transmission				
500 KV	2,921	—	—	—
345 KV	13,182	3,019	5,421	11,676
230 KV	2,300	—	12,280	9,845
161 KV	640	1,817	—	—
138 KV	—	—	92	—
115 KV	8,113	1,835	5,015	14,953
Less than 115 KV	6,627	5,324	1,796	4,501
Total Transmission	33,783	11,995	24,604	40,975
Distribution				
Less than 115 KV	86,549	28,293	81,589	24,878
Total	**120,332**	**40,288**	**106,193**	**65,853**

Electric utility transmission and distribution substations at Dec. 31, 2024:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Substations	354	201	235	454

Natural gas utility mains at Dec. 31, 2024:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	78	3	1,998	35	11
Distribution	10,938	2,610	24,112	—	—

ITEM 3 — 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 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Stock Data

Xcel Energy Inc.'s common stock is listed on the Nasdaq Global Select Market (Nasdaq). The trading symbol is XEL. The number of common stockholders of record as of Feb. 20, 2025 was 43,159.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P 500 Composite Stock Price Index over the last five years.

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 38 companies at year-end and is a broad measure of industry performance.

Comparison of Five Year Cumulative Total Return*

601

* $100 invested on Dec. 31, 2019 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2024, 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 — [RESERVED]

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 ongoing ROE, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that is adjusted from measures calculated and presented in accordance with GAAP.

Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

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

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

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

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. For instance, to present ongoing earnings and ongoing diluted EPS, we may adjust the related GAAP amounts for certain items that are non-recurring in nature. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

The following table provides a reconciliation of GAAP earnings (net income) to ongoing earnings:

(Millions of Dollars)	2024	2023
GAAP net income	$ 1,936	$ 1,771
Loss on Comanche Unit 3 litigation	—	35
Workforce reduction expenses	—	72
Sherco Unit 3 2011 outage refunds	47	—
Less: tax effect of adjustments	(13)	(27)
Ongoing earnings [(a)]	$ 1,969	$ 1,851

(a) Amounts may not add due to rounding.

Diluted Earnings (Loss) Per Share	Twelve Months Ended Dec. 31, 2024 GAAP Diluted EPS	Impact of Adjustments	Ongoing Diluted EPS
NSP-Minnesota	$ 1.41	$ 0.06	$ 1.47
PSCo	1.39	—	1.39
SPS	0.70	—	0.70
NSP-Wisconsin	0.24	—	0.24
Earnings from equity method investments — WYCO	0.03	—	0.03
Regulated utility [(a)]	3.76	0.06	3.83
Xcel Energy Inc. and Other	(0.33)	—	(0.33)
Total [(a)]	$ 3.44	0.06	$ 3.50

Diluted Earnings (Loss) Per Share	Twelve Months Ended Dec. 31, 2023 GAAP Diluted EPS	Impact of Adjustments	Ongoing Diluted EPS
NSP-Minnesota	$ 1.28	$ 0.04	$ 1.32
PSCo [(a)]	1.26	0.08	1.33
SPS	0.70	0.01	0.71
NSP-Wisconsin	0.25	—	0.25
Earnings from equity method investments — WYCO	0.04	—	0.04
Regulated utility [(a)]	3.52	0.14	3.66
Xcel Energy Inc. and Other	(0.31)	—	(0.31)
Total [(a)]	$ 3.21	0.14	$ 3.35

(a) Amounts may not add due to rounding.

Adjustments to GAAP net income include:

Sherco Unit 3 2011 Outage Refunds **—** NSP-Minnesota's Sherco Unit 3 experienced an extended outage following a 2011 incident which damaged its turbine. In 2024, following contested case procedures, Xcel Energy recognized a customer refund of $47 million for replacement power incurred during the outage.

Comanche Unit 3 Litigation — In the third quarter of 2023, PSCo recognized a non-recurring $34 million charge as a result of a jury verdict in Denver County District Court awarding CORE Electric Cooperative lost power damages and other costs.

Workforce Reduction — In 2023, Xcel Energy implemented workforce actions to align resources and investments with our evolving business and customer needs and streamline the organization for long-term success. Xcel Energy initiated a Voluntary Retirement Program, under which approximately 400 eligible non-bargaining employees retired. Xcel Energy also eliminated approximately 150 non-bargaining employees through an involuntary severance program. Workforce reduction expenses of $72 million were recorded in the fourth quarter of 2023.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

Diluted Earnings (Loss) Per Share	2024	2023
NSP-Minnesota	$ 1.41	$ 1.28
PSCo	1.39	1.26
SPS	0.70	0.70
NSP-Wisconsin	0.24	0.25
Earnings from equity method investments — WYCO	0.03	0.04
Regulated utility [(a)]	3.76	3.52
Xcel Energy Inc. and Other	(0.33)	(0.31)
GAAP Diluted EPS [(a)]	3.44	3.21
Loss on Comanche Unit 3 litigation	—	0.05
Workforce reduction expenses	—	0.09
Sherco Unit 3 2011 outage refunds	0.06	—
Ongoing Diluted EPS [(a)]	$ 3.50	$ 3.35

(a) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating Xcel Energy and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, reporting results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

2024 Comparison with 2023

Xcel Energy — GAAP earnings were $3.44 per share compared to $3.21 per share in 2023 and ongoing earnings were $3.50 per share in 2024, compared with $3.35 per share in 2023. The change in EPS was driven by increased recovery of infrastructure investments, partially offset by higher depreciation, interest charges and O&M expenses.

Fluctuations in electric and natural gas revenues associated with changes in fuel and purchased power and/or natural gas sold and transported generally do not significantly impact earnings (changes in costs are offset by the related variation in revenues).

NSP-Minnesota — GAAP earnings increased $0.13 per share and ongoing earnings increased $0.15 per share for 2024 compared to 2023. Ongoing earnings increased due to higher recovery of electric and natural gas infrastructure investments, partially offset by increased depreciation and interest charges.

PSCo — GAAP earnings increased $0.13 per share and ongoing earnings increased $0.06 per share for 2024. Higher ongoing earnings primarily reflects higher recovery of electric and natural gas infrastructure investments, which was partially offset by increased depreciation, O&M and interest charges.

SPS — GAAP earnings were flat and ongoing earnings decreased $0.01 per share for 2024. Ongoing earnings were impacted by increased depreciation, O&M and interest charges, largely offset by regulatory rate outcomes and sales growth.

NSP-Wisconsin — GAAP and ongoing earnings decreased $0.01 per share for 2024. The decrease in ongoing earnings was primarily a result of higher depreciation.

Xcel Energy Inc. and Other — Primarily includes financing costs and interest income at the holding company and earnings from investment funds, which are accounted for as equity method investments. The decline in earnings for 2024 is largely due to higher debt levels and increased interest rates, partially offset by a gain on debt repurchases.

Changes in Diluted EPS

Components significantly contributing to changes in 2024 EPS compared with 2023:

Diluted Earnings (Loss) Per Share	Twelve Months Ended Dec. 31
GAAP diluted EPS — 2023	**$ 3.21**
Components of change — 2024 vs. 2023	
Electric regulatory rate outcomes and riders	0.73
Higher other income, net	0.16
Natural gas regulatory rate outcomes and riders	0.14
Workforce reduction expenses	0.09
Loss on Comanche Unit 3 litigation	0.05
Higher depreciation and amortization	(0.40)
Interest charges, net of AFUDC - debt	(0.24)
Higher O&M expenses	(0.13)
Sherco Unit 3 2011 outage refunds	(0.06)
Other, net	(0.11)
GAAP diluted EPS — 2024	**$ 3.44**
Sherco Unit 3 2011 outage refunds	0.06
Ongoing diluted EPS — 2024	**$ 3.50**

ROE for Xcel Energy and its utility subsidiaries:

	2024		2023	
ROE	GAAP ROE	Ongoing ROE	GAAP ROE	Ongoing ROE
NSP-Minnesota	9.07 %	9.46 %	8.82 %	9.11 %
PSCo	7.63	7.63	7.32	7.77
SPS	9.57	9.57	9.80	9.98
NSP-Wisconsin	8.98	8.98	10.38	10.67
Utility Subsidiaries	8.55	8.69	8.45	8.79
Xcel Energy	10.42	10.61	10.33	10.79

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, electric sales true-up and gas decoupling mechanisms in Minnesota predominately mitigate the positive and adverse impacts of weather in that jurisdiction.

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.

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, CDD and THI:

	2024 vs. Normal	2023 vs. Normal	2024 vs. 2023
HDD	(15.4)%	(7.3)%	(9.8)%
CDD	28.1	5.2	23
THI	(11.2)	16.0	(22.5)

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

	2024 vs. Normal	2023 vs. Normal	2024 vs. 2023
Retail electric	$ (0.008)	$ 0.013	$ (0.021)
Decoupling and sales true-up	0.047	(0.007)	0.054
Electric total	$ 0.039	$ 0.006	$ 0.033
Firm natural gas	(0.070)	(0.010)	(0.060)
Decoupling	$ 0.027	$ 0.013	$ 0.014
Gas total	$ (0.043)	$ 0.003	$ (0.046)
Total	$ (0.004)	$ 0.009	$ (0.013)

Sales — Sales growth (decline) for actual and weather-normalized sales:

	2024 vs. 2023				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(4.1) %	3.9 %	0.7 %	(3.5) %	(0.4) %
Electric C&I	(2.6)	—	9.3	(1.9)	1.7
Total retail electric sales	(3.1)	1.3	7.8	(2.4)	1.1
Firm natural gas sales	(8.0)	(6.9)	N/A	(7.5)	(7.2)

	2024 vs. 2023				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	0.2 %	0.9 %	(1.2)%	(1.5) %	0.2 %
Electric C&I	(1.7)	(1.1)	9.3	(1.6)	1.7
Total retail electric sales	(1.1)	(0.4)	7.4	(1.5)	1.3
Firm natural gas sales	(1.1)	0.6	N/A	(2.5)	(0.2)

	2024 vs. 2023 (Leap Year Adjusted)				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(0.1) %	0.7 %	(1.5)%	(1.8) %	(0.1) %
Electric C&I	(2.0)	(1.4)	9.0	(1.8)	1.5
Total retail electric sales	(1.4)	(0.7)	7.1	(1.8)	1.0
Firm natural gas sales	(1.7)	—	N/A	(3.1)	(0.7)

Annual weather-normalized and leap year adjusted electric sales growth (decline)

- NSP-Minnesota — Residential sales declined due to a 1.5% decrease in use per customer, partially offset by a 1.4% increase in customers. The decline in C&I sales was due to lower use per customer, particularly in the manufacturing sector.
- PSCo — Residential sales increased due to a 1.4% increase in customers, partially offset by a 0.7% decrease in use per customer. The decline in C&I sales was attributable to decreased use per customer, particularly in the wholesale trade and mining.
- SPS — Residential sales declined due to a 2.2% decrease in use per customer partially offset by a 0.7% increase in customers. C&I sales increased due to higher use per customer, primarily driven by the energy sector and cryptocurrency mining.
- NSP-Wisconsin — Residential sales declined due to a 2.7% decrease in use per customer, offset by a 1.0% increase in customers. The C&I sales decline was associated with lower use per customer, experienced particularly in the professional services and manufacturing sectors.

Annual weather-normalized and leap year adjusted natural gas sales growth (decline)

- Natural gas sales reflect 1.7% residential use per customer and 1.4% C&I use per customer decreases. Partially offsetting these were increased residential and C&I customers in all jurisdictions.

Electric Revenues

Electric revenues are impacted by changing sales, fluctuations in the price of natural gas, coal and uranium, regulatory outcomes, market prices and seasonality. In addition, electric customers receive a credit for PTCs generated (wind, nuclear and solar), which reduce electric revenue and income taxes.

(Millions of Dollars)	2024 vs. 2023
Recovery of lower cost of electric fuel and purchase power	(479)
PTCs flowed back to customers (offset by lower ETR)	(302)
Wholesale generation revenues	(96)
Sherco Unit 3 2011 outage refunds	(47)
Regulatory rate outcomes (MN, CO, TX, and NM)	372
Non-fuel riders	169
Conservation and demand side management (offset in expense)	102
Estimated impact of weather (net of sales true-up)	24
Other, net	(42)
Total decrease	$ (299)

Natural Gas Revenues

Natural gas revenues vary with changing sales, the cost of natural gas and regulatory outcomes.

(Millions of Dollars)		2024 vs. 2023
Recovery of lower cost of natural gas	$	(496)
Estimated impact of weather (net of decoupling)		(35)
Retail sales decline (net of decoupling)		(1)
Regulatory rate outcomes (MN, WI, CO, and ND)		91
Infrastructure and integrity riders		8
Other, net		18
Total decrease	$	(415)

Electric Fuel and Purchased Power — Expenses incurred for electric fuel and purchased power are impacted by fluctuations in market prices of natural gas, coal and uranium, as well as seasonality. These incurred expenses are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are largely offset in operating revenues and have minimal earnings impact.

Electric fuel and purchased power expenses decreased $490 million in 2024. The decrease is primarily due to timing of fuel recovery mechanisms and lower commodity prices, partially offset by increased volumes.

Cost of Natural Gas Sold and Transported — Expenses incurred for the cost of natural gas sold are impacted by market prices and seasonality. These costs are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are largely offset in operating revenues and have minimal earnings impact.

Natural gas sold and transported decreased $505 million in 2024. The decrease is primarily due to lower commodity prices and volumes.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $96 million in 2024 primarily due to operational activities, including generation maintenance, storm response, wildfire mitigation costs and damage prevention. The impact of prior year regulatory deferrals also contributed to increased O&M expenses, partially offset by lower labor and benefit costs and lower bad debt expenses.

Depreciation and Amortization — Depreciation and amortization increased $296 million for the year, primarily related to system expansion, partially offset by the impacts of various rate cases, including recognition of previously deferred costs as well as wind and nuclear life extensions.

Other Income — Other income increased $121 million for the year, primarily related to interest earned on significant cash balances throughout the year and a gain on debt repurchases, which helped to offset increased spending in our electric and natural gas operations to reduce risk, including wildfire mitigation.

Interest Charges — Interest charges increased $200 million in 2024. The increase was largely due to higher long-term debt levels to fund capital investments and higher interest rates.

AFUDC, Equity and Debt — AFUDC increased $99 million in 2024. This increase was largely due to increased investment in renewable and transmission projects.

Xcel Energy Inc. and Other Results

Net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

(Millions of Dollars)		2024		2023
Xcel Energy Inc. financing costs	$	(223)	$	(174)
Xcel Energy Inc. taxes and other results [(a)]		38		1
Total Xcel Energy Inc. and other costs	$	(185)	$	(173)

(Diluted Earnings (Loss) Per Share)		2024		2023
Xcel Energy Inc. financing costs	$	(0.40)	$	(0.32)
Xcel Energy Inc. taxes and other results [(a)]		0.07		0.01
Total Xcel Energy Inc. and other costs	$	(0.33)	$	(0.31)

(a) Amounts include gain from open market debt repurchases in 2024.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

2023 Comparison with 2022

A discussion of changes in Xcel Energy's results of operations, cash flows and liquidity and capital resources from the year ended Dec. 31, 2022 to Dec. 31, 2023 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2023, which was filed with the SEC on Feb. 21, 2024. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

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 and credit quality.

See Rate Matters and Other within Note 12 to the consolidated financial statements for further information.

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
SDPUC	Retail rates, services and other aspects of electric operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in South Dakota. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.
MISO	NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.
DOT	Pipeline safety compliance.
Minnesota Office of Pipeline Safety	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider	Recovers costs of conservation and DSM programs. Minnesota state law requires NSP-Minnesota to spend 2% of its state electric revenues and 0.5% of its state natural gas revenues on CIP. These costs are recovered through an annual cost-recovery mechanism.
Customer Protection Mechanisms	MISO capacity revenue tracker, property tax tracker, annual incentive plan, capital true-up, deferred tax asset refund and credit card fee tracker are all mechanisms that mitigate the impact of changes to costs as compared to a baseline for NSP-Minnesota customers.
Decoupling	Measures natural gas revenues against a baseline revenue per-customer for all Minnesota gas customers in classes with more than 50 customers.
FCA	Recovers prudently incurred costs of fuel related items and purchased energy (Minnesota, North Dakota and South Dakota).
Gas Utility Infrastructure Cost Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs in Minnesota.
Infrastructure Rider	Recovers costs for investments in generation in South Dakota.
Purchased Gas Adjustment	Provides for prospective monthly rate adjustments in Minnesota and North Dakota for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actual costs.
Renewable Development Fund Rider	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies in Minnesota.
Renewable Energy Rider	Recovers cost of renewable generation in North Dakota.
RES Rider	Recovers cost of renewable generation in Minnesota.
Sales True-up	Mitigates the impact of changes to sales levels as compared to a baseline for all Minnesota electric customers.
State Energy Policy Electric Rider	Recovers costs associated with the Prairie Island Legislation settlement and the Reliability Administrator/ Sustainable Building Guidelines in Minnesota.
Transmission Cost Recovery Rider	Recovers costs for investments in Minnesota, North Dakota, and South Dakota for electric transmission and distribution grid modernization.

Pending and Recently Concluded Regulatory Proceedings

2024 Minnesota Natural Gas Rate Case — In November 2023, NSP-Minnesota filed a request with the MPUC for a natural gas rate increase of approximately $59 million, or 9.6%.

In June 2024, NSP-Minnesota and various parties filed an uncontested settlement, which includes the following terms:

- Natural gas rate increase of $46 million, or 7.5%.
- ROE of 9.6%.
- Equity ratio of 52.5%.
- Rate base of $1.25 billion.
- No change to Commission approved decoupling.

In October 2024, an ALJ recommended the MPUC approve the rate case settlement. In February 2025, the MPUC verbally approved the settlement agreement. NSP-Minnesota expects to implement a rate increase of $50 million (trued up for 2024 weather normalized actual sales) in July 2025.

2024 North Dakota Natural Gas Rate Case — In December 2023, NSP-Minnesota filed a request with the NDPSC seeking an increase in natural gas rates of $8.5 million (9.4%), based on a ROE of 10.20%, an equity ratio of 52.5%, 2024 test year and rate base of $168 million.

In November 2024, the NDPSC approved a settlement, reflecting a natural gas rate increase of $7.2 million (8.0%), based on a ROE of 9.9% and an equity ratio of 52.5%. Rates were implemented on Jan. 1, 2025.

2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC.

In July 2023, the MPUC approved a three-year rate increase of approximately $332 million for 2022-2024, based on a ROE of 9.25% and an equity ratio of 52.5%. The MPUC also approved a continuation of the sales true-up mechanism.

In November 2023, NSP-Minnesota filed an appeal to the Minnesota Court of Appeals regarding MPUC decisions relating to executive compensation, insurance expense and treatment of prepaid pension assets.

In January 2025, the Court issued its opinion, which upheld the commission's determination on insurance expense, but reversed and remanded the executive compensation and prepaid pension asset decisions back to the MPUC. The opinion is currently pending further action from the MPUC.

2024 Minnesota Electric Rate Case — In November 2024, NSP-Minnesota filed an electric rate case in Minnesota, seeking a total revenue increase of $491 million (13.2%) over two years, based on an ROE of 10.3%, a 52.5% equity ratio and rate base of $13.2 billion in 2025 and $14 billion in 2026. NSP-Minnesota also requested interim rates of $224 million for 2025. In December 2024, the MPUC reduced the interim rate request for wildfire mitigation costs (as these costs were deemed as new costs not previously approved in a rate case) and approved interim rates of $192 million, effective January 1, 2025. A decision is expected in 2026.

2024 North Dakota Electric Rate Case — In December 2024, NSP-Minnesota filed a request with the NDPSC for an annual electric rate increase of approximately $45 million, or 19.3% over current rates established in 2021. The filing is based on a 2025 forecast test year and includes a requested ROE of 10.3%, rate base of approximately $817 million and an equity ratio of 52.5%. In January 2025, the NDPSC approved interim rates, subject to refund, of approximately $27 million (implemented on Feb. 1, 2025).

Nuclear Power Operations

Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment contaminated through use.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs and expects to recover future compliance costs.

Low-Level Waste Disposal — Low level waste from Monticello and Prairie Island is disposed of at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site through 2033 at Prairie Island Unit 1, 2034 at Prairie Island Unit 2, and 2040 at Monticello, which would allow both plants to continue to operate if off-site low-level waste disposal facilities become unavailable.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. Currently, there are no definitive plans for a permanent federal storage facility site.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until 2040 for Monticello, 2033 for Prairie Island Unit 1, and 2034 for Prairie Island Unit 2.

In December 2024, the NRC approved a Subsequent License Renewal application for extended Monticello Plant operation through 2050 (Subsequent Renewed Facility Operating License No. DPR-22, Accession No. ML24310A345). NSP-Minnesota will need authorization from the MPUC for additional storage capacity through 2050.

In February 2024, NSP-Minnesota filed a CON with the MPUC for additional storage at Prairie Island to support possible life extension to 2054. NSP-Minnesota has notified the NRC of intent to apply for Prairie Island SLR which would extend operation of Unit 1 to 2053 and Unit 2 to 2054.

Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PSCW	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. Pipeline safety compliance.
MPSC	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce.
MISO	NSP-Wisconsin is a transmission owning member of the MISO RTO that operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Annual Fuel Cost Plan	NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a 2% annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the most recently authorized ROE. Under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.
Natural Gas Cost-Recovery Factor (MI)	NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, based on 12-month projections and trued-up to actual amounts on an annual basis.
Power Supply Cost Recovery Factors	NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from customers.
Purchased Gas Adjustment	A retail cost-recovery mechanism to recover the actual cost of natural gas, transportation, and storage services.
Wisconsin Energy Efficiency Program	The primary energy efficiency program is funded by the utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from customers.

Pending Regulatory Proceedings

Michigan Electric Rate Case — In July 2024, NSP-Wisconsin filed a Michigan electric rate case with the MPSC. In December 2024, the MPSC approved NSP-Wisconsin's settlement agreement. The settlement order includes an electric rate increase of $1.75 million in 2025 and a step increase of $0.55 million in 2026, based on a ROE of 9.8% and an equity ratio of 50%.

Wisconsin 2025 Stay-Out Proposal — In June 2024, NSP-Wisconsin filed a 2025 stay-out proposal with the PSCW. In December 2024, the PSCW approved NSP-Wisconsin's filing, which offsets $27 million in electric deficiencies and $3 million in natural gas deficiencies by amortizing IRA deferrals, stopping a deferral related to IRA benefits ordered in a previous rate case, and deferring revenue requirement impacts of two natural gas capital projects.

Excess Liability Insurance Deferral – In February 2025, NSP-Wisconsin filed a request with the PSCW for deferred accounting treatment for excess liability insurance expense of $9.6 million incurred as a result of the October 2024 policy renewal. A PSCW decision is expected in the third quarter of 2025.

NSP System

Pending and Recently Concluded Regulatory Proceedings

Resource Acquisition — In February 2024, NSP filed its Upper Midwest Resource Plan with the MPUC. In October 2024, NSP-Minnesota filed a settlement with several parties reaching agreement on the resource plan, as well as the proposed projects to be approved in the pending 800 MW firm dispatchable resource acquisition.

In February 2025, the MPUC verbally approved the terms of the settlement agreement, including:

- The selection of the company owned 420 MW Lyon County combustion turbine.
- The selection of the company owned 300 MW 4-hour Sherco battery energy storage system.
- Multiple PPAs to proceed to the negotiation stage.
- The addition of 3,200 MW of wind, 400 MW of solar and 600 MW of stand-alone storage to be added through 2030 based on an RFP process (a portion of which is expected to be fulfilled with the resources acquired as part of the 2024 RFPs). Of these amounts, approximately 2,800 MW of wind are projected to utilize the Minnesota Energy Connection transmission line.
- Planned life extensions of the Prairie Island and Monticello nuclear plants through the early 2050s.

Additionally, the MPUC approved life extensions of the Red Wing and Mankato RDF plants to 2037 and ordered NSP-Minnesota to file a proposed tariff for customers with super-large load, largely data centers, by July 15, 2025.

NSP-Minnesota will file additional RFPs for approved resource needs beginning in late 2025 or early 2026.

NSP-Minnesota and NSP-Wisconsin are actively engaged in multiple processes and proceedings to acquire resources to meet their identified generation resource needs.

- In October 2023, NSP-Minnesota issued an RFP seeking 1,200 MW of wind assets to replace capacity and reutilize interconnection rights associated with the retiring Sherco coal facilities. The RFP closed in December 2023. NSP-Minnesota expects to file for approval of recommended projects in summer 2025.
- In 2024, NSP-Minnesota and NSP-Wisconsin each issued an RFP collectively seeking up to 1,600 MW of wind, solar, storage or hybrid resources to interconnect to the NSP System, including reutilization of the interconnection rights associated with the retiring Sherco coal units, and 650 MW of solar and storage resources to specifically reutilize the interconnection rights associated with the retiring King coal unit. Bids are currently under evaluation; NSP-Minnesota and NSP-Wisconsin announced the short listed projects in January 2025 and plan to file for the requisite approvals of the selected resources with the MPUC and PSCW, respectively, in the second half of 2025.

Purchased Power and Transmission Services

The NSP System expects to use power plants, power purchases, conservation and DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — Through the Interchange Agreement, NSP-Wisconsin receives power purchased by NSP-Minnesota from other utilities and independent power producers. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to these hedging activities. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota and NSP-Wisconsin do not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information on Regulatory Authority
CPUC	Retail rates, accounts, services, issuance of securities and other aspects of electric, natural gas and steam operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plans greater than 50 MW. Pipeline safety compliance.
FERC	Wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. Wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.
RTO	PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP and participates in the SPP Western Energy Imbalance Service market, an energy imbalance market.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Colorado Energy Plan Adjustment	Recovers the early retirement costs of Comanche Units 1 and 2 to a maximum of 1% of the customer's bill.
DSM Cost Adjustment	Recovers electric and gas DSM, interruptible service costs and performance incentives for achieving energy savings goals.
Electric Commodity Adjustment	Recovers fuel and purchased energy costs. Short-term sales margins are shared with customers. PTCs earned for owned wind generation are returned to customers.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
Purchased Capacity Cost Adjustment	Recovers purchased capacity payments.
RES Adjustment	Recovers the incremental costs of compliance with the RES with a maximum of 1% of the customer's bill.
Steam Cost Adjustment	Recovers fuel costs to operate the steam system. The Steam Cost Adjustment rate is revised quarterly.
Transmission Cost Adjustment	Recovers costs between rate cases for transmission projects that result in a net increase in capacity or are part of an approved wildfire mitigation plan. Distribution projects are recoverable for 2024 and 2025, subject to a cap of 0.5% and 1.25% of electric retail revenues, respectively.
Transportation Electrification Plan	Recovers costs associated with the investment in and adoption of transportation electrification infrastructure.

Pending and Recently Concluded Regulatory Proceedings

Colorado Natural Gas Rate Case — In January 2024, PSCo, filed a request with the CPUC seeking an increase to retail natural gas rates of $171 million (9.5%). The request was based on a 10.25% ROE, an equity ratio of 55%, a 2023 test year and a $4.2 billion year-end rate base.

In October 2024, as modified on ARRR in January 2025, the CPUC issued an order including the following key decisions:

- Use of a historic 2023 test year, with a 13-month average rate base.
- Weighted-average cost of capital of 7.0%, based on an ROE range of 9.2%-9.5% and an equity ratio range of 52%-55%.
- Acceleration of $15 million per year of depreciation expense (incremental to PSCo's original rate request), to be held in an external trust for future decommissioning costs.
- Modifications to recoverability of certain operating expenses.
- Denial of PSCo's decoupling proposal.

PSCo placed new rates into effect in November, as modified on ARRR in February 2025, with an annual revenue increase of approximately $125 million, inclusive of $15 million of accelerated depreciation. The UCA filed a second ARRR in February 2025, which remains pending.

Colorado Resource Plan — In December 2023, the CPUC approved a portfolio of 5,835 MW, which includes approximately 3,100 MW of company owned resources and 2,700 MW of PPAs.

In December 2023, the CPUC approved a framework for two PIMs associated with the generation projects in the portfolio — a PIM related to capital construction costs and another related to ongoing levelized energy costs with details to be further defined via subsequent proceedings throughout 2024. In September 2024, PSCo filed a proposal for implementation of the PIMs. Intervenor testimony is due Feb. 27, 2025, with a final decision expected in summer 2025.

In September 2024, PSCo filed a proposed framework for CPUC review of pricing adjustments for both company owned and PPA resources to enable delivery of the approved portfolio in light of supply chain and geopolitical developments. In January 2025, the CPUC issued a decision granting limited potential pricing relief, subject to evaluation in future CPCN proceedings for company owned projects.

PSCo filed or expects to file generation and transmission CPCNs throughout 2024 and 2025.

2024 Colorado Electric Resource Plan — In October 2024, PSCo filed its electric resource plan with the CPUC. The filing reflects the expected growth on the system, the generation resources needed to meet the projected growth and the future evaluation of competitive bids for new generation resources.

- The plan reflects a base sales forecast with 7% compound annual sales growth through 2031.
- The plan also presents a low sales forecast with a 3% compound annual sales growth through 2031.
- The resource plan includes forecasted need of 5-14 GW of new generation capacity through 2031, including renewables and firm dispatchable resources to meet the two different scenarios. The acquisitions of generation resources will be determined through a competitive solicitation after the CPUC determines the portfolio. The table below summarizes two of the proposed portfolios based on the different sales scenarios:

(MW)	Base Plan	Low Load
Wind	7,250	2,800
Solar	3,077	1,200
Natural gas combustion turbine	1,575	1,400
Storage (long duration)	1,600	—
Other storage	450	—
Total	13,952	5,400

The procedural schedule is as follows:

- Answer testimony: April 18, 2025
- Rebuttal testimony: May 23, 2025
- Settlement deadline: June 2, 2025
- Hearing: June 10-20, 2025
- Statements of position: July 14, 2025

A CPUC decision on the resource plan is expected by the fall of 2025 (Phase I) with the competitive solicitation for resource additions expected in early 2026.

Wildfire Mitigation Plan — In June 2024, PSCo filed an updated WMP and request for recovery of costs covering the years 2025 to 2027 with the CPUC. The estimated total cost for this plan is approximately $1.9 billion. A CPUC decision is expected in the third quarter of 2025.

The WMP integrates industry experience; incorporates evolving risk assessment methodologies; adds new technology; and expands the scope, pace and scale of our work to reduce wildfire risk in a comprehensive and efficient manner under four core programs that include the following:

- Situational awareness — Meteorology, area risk mapping and modeling, artificial intelligence cameras and continuous monitoring.
- Operational mitigations – Enhanced powerline safety settings and PSPS.
- System resiliency — Asset assessment and remediations, pole replacements, line rebuilds, targeted undergrounding and vegetation management.
- Customer support — Coordination and real-time data sharing with customers and other stakeholders and PSPS resiliency rebates.

In February 2025, six of the nine intervenors filed answer testimony in the proceeding. Intervenors provided a range of recommendations related to both the scope of proposed work and the cost recovery proposal.

The remaining procedural schedule is as follows:

- Rebuttal testimony: March 21, 2025
- Settlement deadline: April 11, 2025
- Hearing: May 5-15, 2025
- Decision deadline: Aug. 28, 2025

Colorado Senate Bill 23-291 — In May 2023, Colorado Senate Bill 23-291 was signed into law. The bill includes a number of topics including natural gas and electric fuel incentive mechanisms, natural gas planning rules, regulatory filing requirements, and non-recovery of certain expenses (e.g., certain organizational or membership dues, tax penalties or fines).

In November 2023, the CPUC approved PSCo's natural gas price risk plan to manage customer bill volatility from commodity price changes, establishing upper and lower limits for changes in the GCA rate. As a result, costs above the upper limit are deferred for future recovery, with interest, and costs below the lower limit deferred as a reserve against future cost increases.

The legislation also calls for the CPUC to adopt rules to establish fuel cost mechanisms to align the financial incentives of a utility with the interests of the utility's customers.

In December 2024, the CPUC adopted final rules applicable to PSCo's natural gas utility that would assign to the Company four percent of the change in the price per MMbtu of natural gas compared to the three-year average, subject to rolling 12-month cap based on a percentage of rate base, currently estimated at $7 million. The rules require PSCo to make a filing to implement the mechanism within sixty days of becoming effective, expected later in 2025.

In December 2024, the CPUC also adopted rules for electric utilities but did not adopt a specific PIM framework, which will be further considered through additional proceedings in 2025.

Colorado Senate Bill 24-218 — In May 2024, Colorado Senate Bill 24-218 was signed into law. The bill includes a suite of policy changes to accelerate investment in electric distribution, including a framework to develop distribution planning and performance requirements and the opportunity for current cost recovery through a rider for distribution investments. In July 2024 and December 2024, the CPUC approved PSCo's request to collect $17 million and $48 million through a rider, over the remainder of 2024 and 2025, respectively, subject to true-up, associated with forecasted capital investments covered by the new legislation.

Excess Liability Insurance Deferral — In August 2024, PSCo filed a request with the CPUC to establish a tracker to defer differences in excess liability insurance premiums after the October 2024 policy renewal (reflecting significantly rising premiums of approximately $40 million, largely associated with wildfire risks throughout the United States) and amounts currently recovered. In January 2025, the CPUC approved a one-year deferral aligned with the current insurance policy year. Cost recovery for incremental insurance premiums will be reviewed in a future rate case.

Purchased Power and Transmission Service Providers

PSCo meets its system capacity and energy requirements through its fleet of owned and purchased electric generation resources and, when required, the use of demand-side management programs.

Purchased Power — PSCo purchases power from other utilities, energy marketers and independent power producers. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. Much of PSCo's long-term purchased power is for wind, solar and storage resources. PSCo makes short-term purchases to meet system load and energy requirements, replace generation out of service for maintenance, meet operating reserve obligations, or obtain energy at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to its customers.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to these hedging activities.

Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of SPS' electric operations. The municipalities in which SPS operates in Texas have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, retail rates and services and the construction of transmission or generation. Reviews Integrated Resource Plans for meeting future energy needs.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP Integrated and Wholesale Markets	SPS is a transmission owning member of the SPP RTO and operates within the SPP RTO and SPP integrated and wholesale markets. SPS is authorized to make wholesale electric sales at market-based prices.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Advanced Metering System Surcharge	Recovers costs incurred in deployment of the Advanced Metering System in Texas.
Consulting Fee Rider	Recovers consulting fees and carrying charges incurred by SPS on behalf of the PUCT.
Distribution Cost Recovery Factor	Recovers distribution costs not included in rates in Texas.
Electric Vehicle Rider	Recovers costs of the Transportation Electrification Plan in New Mexico.
Energy Efficiency Cost Recovery Factor	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses in Texas. Regulations require refunding or surcharging over- or under-recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis if this condition is expected to continue.
Fuel and Purchased Power Cost Adjustment Clause	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico.
Grid Modernization Rider	Recovers costs incurred in the implementation of Grid Modernization Components in New Mexico.
Renewable Portfolio Standards	Recovers deferred costs for renewable energy programs in New Mexico.
Transmission Cost Recovery Factor	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

2023 Texas Electric Rate Case — In 2023, SPS filed an electric rate case with the PUCT seeking an increase in base rate revenue of $158 million (14%). Interim rates went into effect on Feb. 1, 2024. In April 2024, the PUCT approved a black box settlement between SPS and intervening parties, which reflect the following terms:

- A base rate increase of $65 million effective back to July 13, 2023.
- A 9.55% ROE, a 54.51% equity ratio and a 7.11% WACC for purposes of calculating SPS' allowance for funds used during construction and in other proceedings filed before the PUCT where a stated WACC is required.
- The reflection in rates of the retirement of Tolk Generation Station from 2034 to 2028.
- Establishment of a rate rider of approximately $18 million to be recovered over a three-year period for various deferred expenses.

In July 2024, SPS filed to surcharge the final under-recovered amount of $37 million. This will be largely offset by previously deferred costs. In February 2025, the PUCT approved the surcharge.

2022 All-Source RFP — In July 2023, SPS filed for approval of a CPCN for a recommended generation portfolio, which includes 418 MW of self-build solar projects and a 36 MW battery. The NMPRC approved the projects in May 2024. In July 2024, the PUCT approved the solar projects and denied the battery project. The PUCT's approval included minimum production and PTC guarantees.

New Mexico Resource Plan (IRP) — In October 2023, SPS filed its IRP with the NMPRC, which supports projected load growth and increasing reliability requirements, and secures replacement energy and capacity for retiring resources. SPS' projected resource needs ranging from approximately 5,300 MW to 10,200 MW by 2030. In February 2024, the NMPRC accepted the IRP.

In July 2024, SPS issued a RFP, seeking approximately 3,200 MW of accredited generation capacity by 2030. The total capacity to be added to the system is expected to align with the range identified in the SPS IRP, depending on the types of resources proposed in the RFP and their accredited capacity factors.

The RFP portfolio selection is expected in May 2025. SPS is expected to file for a CON for the recommended portfolio in the summer of 2025. The PUCT and NMPRC are expected to rule on the portfolio in 2026.

Texas System Resiliency Plan — In December 2024, SPS filed its Texas SRP with the PUCT. Consistent with PUCT requirements, SPS' proposed plan discusses resiliency-related risks and the five measures that have been designed to help SPS prevent, withstand, mitigate or more promptly recover from resiliency events, including wildfire.

The SRP includes the following measures:

- Distribution overhead hardening — Replacing and reinforcing key components of the distribution overhead system.
- Distribution system protection modernization — Installing enhanced reclosers, communications equipment and replacing substation relay panels and breakers.
- Communication modernization — Building out a private LTE network, installing fiber optic cable and adding remote terminal units.
- Operational flexibility — Procuring mobile substation equipment and installing additional switching devices.
- Wildfire mitigation — Weather stations, modeling, deploying artificial intelligence and vegetation management.

The plan covers 2025-2028 and includes the following total spend:

(Millions of Dollars)	Capital	O&M	Total
Distribution overhead hardening	$ 253	$ —	$ 253
Distribution system protection modernization	92	—	92
Communication modernization	112	—	112
Operational flexibility	44	—	44
Wildfire mitigation	20	17	37
Total	$ 521	$ 17	$ 538

The procedural schedule is as follows:

- Intervenor testimony: February 28, 2025
- Staff testimony: March 7, 2025
- Rebuttal testimony: March 17, 2025
- Hearing: March 25-26, 2025

A PUCT decision is expected in the summer of 2025.

Purchased Power Arrangements and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Natural Gas

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates limited natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines, subject in certain cases to the regulation of the Railroad Commission of Texas. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA, DOT and PUCT for pipeline safety compliance.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price risk and to hedge sales and purchases. Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Other

Supply Chain

Xcel Energy's ability to meet customer energy requirements, growing customer demand, respond to storm-related disruptions, and execute our capital expenditure program are dependent on maintaining an efficient supply chain.

Large global demand for energy-related infrastructure has stretched equipment supply chains, extended delivery dates and increased prices for items like combustion turbines, transformers and other large electrical equipment. The labor market for skilled engineering and construction resources to build renewables and gas generation has also been strained, impacting cost and availability.

In addition, manufacturing processes have experienced disruptions related to the scarcity of certain raw materials and interruptions in production and shipping. The impact of inflationary pressures, geopolitical events and federal policies have exacerbated the situation. Xcel Energy continues to monitor the situation as it remains fluid and seeks to mitigate the impacts by securing alternative suppliers and key vendor partners, increasing procurement lead times, modifying design standards, and adjusting the timing of work.

Tariffs and Trade Complaints

In May 2024, the U.S. Department of Commerce announced the initiation of anti-dumping and countervailing duty investigations of CSPV cells from Cambodia, Malaysia, Thailand and Vietnam, whether or not assembled into modules.

In October 2024, the U.S. Department of Commerce announced its preliminary determination in the countervailing duty circumvention investigation, which is not expected to impact Xcel Energy projects. In November 2024, the U.S. Department of Commerce concluded that dumping had occurred and the impact to Xcel Energy is still being evaluated.

In May 2024, the White House imposed a new 25% tariff on Lithium-Ion storage along with other trade measures. The tariff went into immediate effect for EV batteries but has a grace period until January 2026 for stationary energy storage applications.

In January of 2025, the U.S. International Trade Commission made an affirmative determination in the preliminary phase of the anti-dumping and countervailing duty investigations concerning Active Anode Material, a component of lithium-ion batteries, from China. This case will be reviewed by the U.S. Department of Commerce and the International Trade Commission over the course of 2025.

In early 2025, several executive orders were issued, some of which impose new tariffs on certain imports, which may impact our procurement activities.

Xcel Energy continues to assess the impacts of these tariffs, trade complaints and federal policies on its business, including company owned projects and PPAs. Xcel Energy may seek regulatory relief for tariffs, if required, in its jurisdictions.

Further policy actions or other restrictions on solar and storage imports, disruptions in imports from key suppliers, or any new trade complaint could impact project timelines and costs of various generation projects and PPAs.

Excess Liability Insurance Coverage

Xcel Energy maintains excess liability coverage, which is intended to insure against liability to third parties. Through the third quarter of 2024, Xcel Energy had approximately $600 million of excess liability coverage; including $520 million of wildfire coverage with an annual premium of approximately $40 million. Examples of claims paid under this policy include property damage or bodily injury to members of the public caused by Xcel Energy's employees, equipment or facilities. The increased wildfire liability risk and claims are driving a significant increase of premiums and reductions in insurance coverage in the excess liability markets, especially in the western United States. In October 2024, Xcel Energy renewed its excess liability coverage and now has $450 million of total coverage; including $450 million of wildfire coverage for the NSP System and $300 million of wildfire coverage for PSCo and SPS. The annual premium for this excess liability insurance is approximately $130 million. Xcel Energy received an approved deferral at PSCo, filed a deferral request at NSP-Wisconsin and will continue to seek to recover these increased costs through various regulatory proceedings, including planned deferral requests or rate filings in several states.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements requires the application of accounting rules and guidance, as well as the use of estimates. Application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and results reported.

Accounting policies and estimates that are most significant to Xcel Energy's results of operations, financial condition or cash flows, and require management's most difficult, subjective or complex judgments are outlined below. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Our rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows.

Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

Each reporting period we assess the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact our results of operations, financial condition or cash flows.

As of Dec. 31, 2024 and 2023, Xcel Energy had regulatory assets of $3.4 billion and $3.4 billion, respectively and regulatory liabilities of $6.9 billion and $6.4 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income.

At Dec. 31, 2024, in assessing the probability of recovery of recognized regulatory assets, unless otherwise disclosed, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the recovery of the assets.

See Notes 4 and 12 to the consolidated financial statements for further information.

Income Tax Accruals

Judgment, uncertainty and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our future ETR. ETR calculations are revised every quarter based on best available year-end tax assumptions, adjusted in the following year after returns are filed. Tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates, including forecasted annual income, permanent tax adjustments and tax credits.

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized.

We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

See Note 7 to the consolidated financial statements for further information.

Employee Benefits

We sponsor several noncontributory, defined benefit pension plans and other postretirement benefit plans that cover almost all employees and certain retirees. Projected benefit costs are based on historical information and actuarial calculations that include key assumptions (annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates, etc.). In addition, the pension cost calculation uses a methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed.

At Dec. 31, 2024, Xcel Energy set the rate of return on assets used to measure pension costs at 7.13%, which is a 20 basis point increase from the rate set at Dec. 31, 2023. The rate of return used to measure postretirement health care costs is 6.25% at Dec. 31, 2024, which is a 125 basis point increase from the rate set in 2023. Xcel Energy's pension investment strategy includes plan-specific investments that seek to align the investment allocations to optimize risk adjusted return and interest rate risk management based on factors that include the plan's funded status. This strategy generally results in a greater percentage of interest rate sensitive securities being allocated to plans with higher funded status ratios and a greater percentage of growth assets being allocated to plans having lower funded status ratios.

Xcel Energy set the discount rates used to value both the pension obligations and postretirement health care obligations at 5.88% at Dec. 31, 2024. This represents a 39 basis point and 34 basis point increase, respectively, from 2023. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Bank of America US Corporate 15+ Bond Index. In addition, Xcel Energy reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2025 pension costs, net of the effects of regulation:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (12)	$ 24
Discount rate	(2)	2

Mortality rates are developed from actual and projected plan experience for pension plan and postretirement benefits. Xcel Energy's actuary conducts an experience study periodically to determine an estimate of mortality. Xcel Energy considers standard mortality tables, improvement factors and the plans actual experience when selecting a best estimate.

As of Dec. 31, 2024, the initial medical trend cost claim assumptions for Pre-65 was 7.0% and Post-65 was 7.5%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

Funding contributions in 2024 were $100 million and will be $125 million in 2025. In future years contributions will decrease slightly but then remain relatively consistent. Investment returns were less than the assumed levels in 2024 and 2022, but were more than the assumed levels in 2023.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year.

As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 14 years in 2024).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $60 million in 2025 and $69 million in 2026, while the actual pension costs were $79 million in 2024 and $74 in 2023. The expected decrease in 2025 is primarily due to the absence of a pension settlement.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2022 - 2025:

- $125 million in January 2025.
- $100 million in 2024.
- $50 million in 2023.
- $50 million in 2022.

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future. Xcel Energy contributed $11 million, $11 million and $13 million during 2024, 2023 and 2022, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $8 million during 2025.

Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on GAAP. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- Regulatory Commissions in Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo is required to create a regulatory liability to the extent expense is less than that included in rates. No adjustment was needed in 2024.

See Note 11 to the consolidated financial statements for further information.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions, it adjusts the carrying amount of both the ARO liability and related long-lived asset. ARO liabilities are accreted to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory liability. The amounts recorded for AROs related to future nuclear decommissioning were $2.5 billion in 2024 and $2.1 billion in 2023.

NSP-Minnesota obtains periodic independent cost studies to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material. In November 2024, the 2025-2027 Triennial Nuclear Plant Decommissioning Study was filed.

The following assumptions have a significant effect on the estimated nuclear obligation:

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the retirement dates approved by the MPUC, which can be different than the expiration dates of each unit's operating license with the NRC (i.e., 2050 for Monticello and 2033 and 2034 for Prairie Island Units 1 and 2, respectively).

In December 2024, the operating license for Xcel Energy's Monticello Nuclear Generating Plant in Monticello, MN was renewed. The approval allows the plant to operate an additional 20 years, through 2050. As of Dec. 31, 2024, the planned retirement dates of the Prairie Island Unit 1 and Unit 2 and Monticello were 2033, 2034 and 2040. In February 2025, the MPUC approved the planned life extension through 2050 as part of the Upper Midwest Resource Plan. These will be incorporated in decommissioning estimates in 2025 once additional approvals have been received.

The estimated timing of the decommissioning activities is based upon the 60 year DECON method, which assumes prompt removal and dismantlement. Decommissioning activities are expected to begin at the commission approved retirement date and be completed for both facilities by approximately 2101.

Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology, experience and regulations could cause cost estimates to change significantly.

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.8% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on weighted averages of labor and non-labor escalation factors.

Discount Rates — Changes in timing or estimated cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity.

If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 3% to 7% have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating future costs including the method to be utilized, ultimate costs to decommission and planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially.

However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

NSP-Minnesota continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time.

This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2024.

See Note 12 to the consolidated financial statements for further information.

Loss Contingencies – Wildfires

The outcomes of legal proceedings and claims brought against Xcel Energy related to the Marshall Fire, Smokehouse Creek Fire Complex or any future wildfire are subject to uncertainty. An estimated loss from a loss contingency such as a legal proceeding or claim is accrued if it is probable of being incurred and the amount of the loss can be reasonably estimated. Each reporting period we evaluate, among other factors, the degree of probability of unfavorable outcomes and the ability to make reasonable estimates of potential losses. The process for evaluating any wildfire-related liabilities requires a series of complex judgments about past and future events. Factors such as the cause of a wildfire, the extent and magnitude of potential damages and the status of investigations and legal proceedings are considered. See Note 12 accompanying the consolidated financial statements for additional information.

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 for a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

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 on the contracts underlying our derivatives, the contracts expose us to credit and non-performance risk.

Distress in the financial markets may impact counterparty risk and the fair value of the securities in the nuclear decommissioning fund and pension fund.

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 Dec. 31, 2024:

	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]	$ (16)	$ (19)	$ (4)	$ —	$ (39)
NSP-Minnesota [b]	3	10	(4)	2	11
PSCo [a]	1	5	—	—	6
	$ (12)	$ (4)	$ (8)	$ 2	$ (22)

	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]	$ —	$ —	$ 20	$ —	$ 20

(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 years ended Dec. 31:

(Millions of Dollars)	**2024**	**2023**
Fair value of commodity trading net contracts outstanding at Jan. 1	$ 1	$ (10)
Contracts realized or settled during the period	—	(2)
Commodity trading contract additions and changes during the period	(3)	13
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (2)	$ 1

A 10% increase and 10% decrease in forward market prices for Xcel Energy's commodity trading contracts would have likewise increased and decreased pretax income from continuing operations, by approximately $2 million at Dec. 31, 2024 and $4 million at Dec. 31, 2023.

The utility subsidiaries' commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations using an industry standard methodology known as VaR. VaR expresses the potential change in fair value of 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 purchases and 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)	**Year Ended Dec. 31**	**Average**	**High**	**Low**
2024	$ —	$ —	$ 1	$ —
2023	—	—	1	—

Nuclear Fuel Supply — NSP-Minnesota has contracted for its 2025 through 2029 enriched nuclear material requirements, which are in various stages of processing in Canada, Europe and the United States. In May 2024, the Prohibiting Russian Uranium Imports Act was signed into law. As such, NSP-Minnesota is no longer permitted to accept deliveries of enriched nuclear material from Russia beginning in August 2024, unless specific waivers are requested and received.

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.

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $7 million and $9 million in 2024 and 2023, respectively.

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

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. Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

The value of pension and postretirement plan assets and benefit costs are impacted by changes in discount rates and expected return on plan assets. Xcel Energy's ongoing pension and postretirement investment strategy is based on plan-specific investment recommendations that seek to optimize potential investment risk and minimize interest rate risk associated with changes in the obligations as a plan's funded status increases over time. The impacts of fluctuations in interest rates on pension and postretirement costs are mitigated by pension cost calculation methodologies and regulatory mechanisms that minimize the earnings impacts of such changes.

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 monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2024, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $26 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $25 million. At Dec. 31, 2023, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $27 million, while a decrease in prices of 10% would have resulted in an decrease in credit exposure of $24 million.

Xcel Energy conducts credit reviews for all wholesale, trading and non-trading commodity counterparties and employs credit risk controls, 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

Derivative contracts, with the exception of those designated as normal purchases and normal sales, are reported at fair value. Xcel Energy's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting. See Notes 10 and 11 to the consolidated financial statements for further information.

Liquidity and Capital Resources

Cash Flows

Operating Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31
Cash provided by operating activities — 2023	$ 5,327
Components of change — 2024 vs. 2023	
Higher net income	165
Non-cash transactions	222
Changes in deferred taxes	284
Changes in working capital	(783)
Changes in net regulatory and other assets and liabilities	(574)
Cash provided by operating activities — 2024	$ 4,641

Net cash provided by operating activities decreased by $686 million for 2024 as compared to 2023. The decrease was largely due to interim rate refunds in Minnesota and timing of recovery of deferred fuel costs, partially offset by the change in deferred income taxes, which includes the impact of proceeds for tax credit transfers.

Investing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31
Cash used in investing activities — 2023	$ (5,926)
Components of change — 2024 vs. 2023	
Increased capital expenditures	(1,510)
Other investing activities	8
Cash used in investing activities — 2024	$ (7,428)

Net cash used in investing activities increased by $1,502 million for 2024 as compared to 2023. The increase in capital expenditures was largely due to continued system expansion and increased investment in renewable and transmission projects.

Financing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31
Cash provided by financing activities — 2023	$ 617
Components of change — 2024 vs. 2023	
Higher long-term debt issuances, net of repayments	1,512
Higher proceeds from issuance of common stock	847
Higher dividends paid to shareholders	(83)
Other financing activities	(56)
Cash provided by financing activities — 2024	$ 2,837

Net cash provided by financing activities increased by $2,220 million for 2024 as compared to 2023. The increase was largely related to additional debt and common stock issuances to fund capital investment.

See Note 5 to the consolidated financial statements for further information.

Capital Requirements

Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. Xcel Energy expects to have adequate amounts of cash from operating and financing activities to meet both its short-term and long-term cash requirements. Xcel Energy's financing requirements are dependent on both existing contractual obligations and other commitments, as well as projected capital forecasts. 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. Projected future financing requirements can be impacted by various factors including constraints to supply chain and labor, regulatory lag and inflation.

Material Cash Requirements and Other Commitments

	Payments Due by Period (as of Dec. 31, 2024)				
(Millions of Dollars)	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**After 5 Years**
Long-term debt, principal and interest payments	$ 50,915	$ 2,292	$ 3,316	$ 3,846	$ 41,461
Finance lease obligations	208	10	17	16	165
Operating leases obligations [(a)]	1,355	271	432	215	437
Unconditional purchase obligations [(b)] [(c)]	3,755	1,432	1,207	432	684
Other long-term obligations, including current portion [(d)]	85	20	36	29	—
Other short-term obligations	632	632	—	—	—
Short-term debt	695	695	—	—	—
Total contractual cash obligations	$ 57,645	$ 5,352	$ 5,008	$ 4,538	$ 42,747

(a) Included in operating lease obligations are $240 million, $372 million, $166 million and $199 million, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that are accounted for as operating leases.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its fuel (nuclear, natural gas and coal) requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into non-lease purchase power agreements. Certain contractual purchase obligations are adjusted on indices. Effects of price changes are mitigated through cost of energy adjustment mechanisms.

(c) Amounts exclude approximately $1 billion of incremental payments related to SPS' renegotiation and extension of a non-lease PPA that received PUCT approval in February 2025. The extension to 2040 will result in annual payments of approximately $65 million to $80 million commencing in 2025.

(d) Primarily consists of contracts for information technology services.

Capital Expenditures — Base capital expenditures for Xcel Energy for 2025 through 2029:

	Actual	Base Capital Forecast (Millions of Dollars)					
By Regulated Utility	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2025 - 2029 Total**
PSCo	$ 3,180	$ 5,820	$ 5,190	$ 3,940	$ 3,780	$ 3,550	$ 22,280
NSP-Minnesota	2,830	3,240	2,500	2,830	2,080	2,570	13,220
SPS	1,100	1,400	1,540	1,280	1,040	1,040	6,300
NSP-Wisconsin	560	640	650	690	660	670	3,310
Other [(a)]	(20)	(100)	(40)	10	10	10	(110)
Total base capital expenditures	$ 7,650	$ 11,000	$ 9,840	$ 8,750	$ 7,570	$ 7,840	$ 45,000

(a) Other category includes intercompany transfers for safe harbor wind turbines.

	Actual	Base Capital Forecast (Millions of Dollars)					
By Function	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2025 - 2029 Total**
Electric distribution	$ 2,220	$ 2,570	$ 3,000	$ 3,400	$ 3,320	$ 3,540	$ 15,830
Electric transmission	1,720	2,260	2,860	2,740	2,390	2,310	12,560
Renewables	1,130	3,360	1,400	260	—	—	5,020
Electric generation	960	1,210	1,150	910	580	620	4,470
Natural gas	780	800	680	690	630	620	3,420
Other	840	800	750	750	650	750	3,700
Total base capital expenditures	$ 7,650	$ 11,000	$ 9,840	$ 8,750	$ 7,570	$ 7,840	$ 45,000

The base plan does not include any potential incremental generation or transmission assets that are pending commission approval through an RFP, a resource plan, or from additional data center load, which could result in additional capital expenditures of $10 billion or greater. Xcel Energy generally expects to fund additional capital investment with approximately 40% equity and 60% 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, 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 2029 — Xcel Energy issues debt and equity securities to refinance retiring debt maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for general corporate purposes.

Current estimated financing plans of Xcel Energy for 2025 through 2029 (includes the impact of tax credit transferability):

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from operations [(a)]	$	25,320
New debt [(b)]		15,180
Equity through the DRIP and benefit program		500
Other equity		4,000
Base capital expenditures 2025 - 2029	$	45,000
Maturing debt	$	3,730

(a) Net of dividends and pension funding.
(b) Reflects a combination of short and long-term debt; net of refinancing.

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.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2025, Xcel Energy announced an increase in the annual dividend of 9 cents per share, which represents an increase of 4.1%.

Xcel Energy's dividend policy balances the following:

- Projected cash generation.
- Projected capital investment.
- A reasonable rate of return on shareholder investment.
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places limits on the ability of public utilities within a holding company to declare dividends. Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

See Note 5 to the consolidated financial statements for further information.

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.

Funded status and pension assumptions:

(Millions of Dollars)		Dec. 31, 2024		Dec. 31, 2023
Fair value of pension assets	$	2,504	$	2,690
Projected pension obligation [(a)]		2,752		2,943
Funded status	$	(248)	$	(253)

(a) Excludes non-qualified plan of $13 million and $12 million at Dec. 31, 2024 and 2023, respectively.

Pension Assumptions	2024	2023
Discount rate	5.88 %	5.49 %
Expected long-term rate of return	7.13	6.93

Capital Sources

Short-Term Funding Sources — Xcel Energy generally funds short-term needs, through operating cash flows, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on construction expenditures, working capital and dividend payments.

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

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

- $1.50 billion for Xcel Energy Inc.
- $700 million for PSCo.
- $700 million for NSP-Minnesota.
- $500 million for SPS.
- $150 million for NSP-Wisconsin.

See Note 5 to the consolidated financial statements for further information.

Credit Facility Agreements — As of Feb. 24, 2025, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)		Facility [(a)]		Drawn [(b)]		Available		Cash		Liquidity
Xcel Energy Inc.	$	1,500	$	660	$	840	$	25	$	865
PSCo		700		101		599		10		609
NSP-Minnesota		700		375		325		7		332
SPS		500		255		245		7		252
NSP-Wisconsin		150		27		123		3		126
Total	$	3,550	$	1,418	$	2,132	$	52	$	2,184

(a) Credit facilities expire in September 2027.
(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 revolving credit facility for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving credit facility for an additional year. All extension requests are subject to majority bank group approval.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2024 and 2023, Xcel Energy had approximately 574 million shares and 555 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC which are uncapped, permitting Xcel Energy Inc. and its utility subsidiaries to issue debt, equity and other securities. Debt issuance at our utility subsidiaries are subject to commission approval.

Long-Term Borrowings, Equity Issuances and Other Financing Instruments — Xcel Energy may issue equity through its ATM program, forward equity agreements or other offerings. Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions, changes in tax policies and other factors.

Planned Financing Activity — Xcel Energy's 2025 financing plans reflect the following:

Issuer	Security	Amount (Millions of Dollars)	Expected Tenor	Anticipated Timing
Xcel Energy Inc.	Senior Unsecured Notes	$ 1,000	10 Year	First Quarter
PSCo	First Mortgage Bonds	2,000	10 Year & 30 Year	Second & Third Quarter
NSP-Minnesota	First Mortgage Bonds	1,100	10 Year & 30 Year	First & Third Quarter
SPS	First Mortgage Bonds	450	30 Year	Second Quarter
NSP-Wisconsin	First Mortgage Bonds	250	30 Year	Second Quarter

See Note 5 to the consolidated financial statements for further information.

Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2025 Earnings Guidance — Xcel Energy's 2025 ongoing earnings guidance is a range of $3.75 to $3.85 per share.[(a)]

Key assumptions as compared with 2024 actual levels unless noted:

- Constructive outcomes in all pending rate case and regulatory proceedings, including requests for deferral of incremental insurance costs associated with wildfire risk and recovery of O&M costs associated with wildfire mitigation plans.
- Normal weather patterns for the year.
- Weather-normalized retail electric sales are projected to increase ~3%.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%.
- Capital rider revenue is projected to increase $260 million to $270 million (net of PTCs).
- O&M expenses are projected to increase ~3%.
- Depreciation expense is projected to increase approximately $210 million to $220 million.
- Property taxes are projected to increase $55 million to $65 million.
- Interest expense (net of AFUDC - debt) is projected to increase $165 million to $175 million, net of interest income.
- AFUDC - equity is projected to increase $110 million to $120 million.

(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. As Xcel Energy is unable to quantify the financial impacts of any additional adjustments that may occur for the year, we are unable to 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 6% to 8% based off of $3.55 per share (the mid-point of 2024 original ongoing earnings guidance of $3.50 to $3.60 per share).
- Deliver annual dividend increases of 4% to 6%.
- Target a dividend payout ratio of 50% to 60%.
- Maintain senior secured debt credit ratings in the A range.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See the "Derivatives, Risk Management and Market Risk" section in Item 7, incorporated by reference.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 15 to the consolidated financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2024. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2024, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an attestation report on Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ ROBERT C. FRENZEL	/s/ BRIAN J. VAN ABEL
Robert C. Frenzel	Brian J. Van Abel
Chairman, President, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 27, 2025	Feb. 27, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Xcel Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management Report on Internal Controls over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements — Refer to Notes 4 and 12 to the consolidated financial statements.
Critical Audit Matter Description

The Company 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. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the "Commissions"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in assets required to deliver services to customers. Accounting for the Company's regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions' regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company's rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery in future rates of incurred costs and requirements to refund amounts to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, other regulatory filings, legal decisions and recommendations being evaluated by the Commissions, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates. We evaluated historic orders for precedents of the Commissions' treatment of similar costs under similar circumstances. We compared the regulatory orders, filings and other publicly available information to the Company's recorded regulatory assets and liabilities for completeness.
- We obtained management's analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

Commitments and Contingencies - Wildfires – Refer to Note 12 to the consolidated financial statements

Critical Audit Matter Description

As a result of wildfires that have occurred in the Company's service territory in Colorado and Texas, the Company is required to evaluate its exposure to potential loss contingencies arising from claims associated with the 2021 Marshall Wildfire and the 2024 Smokehouse Creek Fire Complex (the "Wildfires"). In evaluating this exposure, the Company is required to determine whether the likelihood of loss for each of the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the Wildfires, investigations, and discovery associated with lawsuits.

A provision for a loss contingency is recorded when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. If deemed reasonably possible, the Company is required to estimate the potential loss or range of potential loss and disclose any material amounts. A current asset for claim amounts that are recoverable from insurance related to a loss contingency is recorded when it is probable the claim will be recovered.

We identified contingencies from the Wildfires and the related disclosures as a critical audit matter due to the significant judgments made by management to determine the probability of loss and estimate the probable losses and insurance recoveries. Auditing the reasonableness of management's judgments, estimates and disclosures related to the Wildfires required a high degree of auditor judgment and increased extent of audit effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding the probability of loss, estimated losses and insurance recoveries, and related disclosures for contingencies related to the Wildfires included the following, among others:

- We tested the effectiveness of controls over (1) the Company's determination of whether a loss was probable and/or reasonably possible and whether recoveries were probable; (2) the determination of the significant assumptions used in estimating the amount of probable loss and probable insurance recoveries; and (3) the disclosures related to the Wildfires.
- We evaluated management's judgments related to whether a loss was probable or reasonably possible from the Wildfires by inquiring of management and the Company's external and internal legal counsel. We also evaluated the potential impact of information gained through the Company and third parties' investigations into the cause of the Wildfires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.
- We evaluated management's methodologies for assessing estimates of loss and recording a probable loss through inquiries with management and external and internal legal counsel and we tested the significant assumptions, including payments to settle claims, used in the estimates of probable loss.
- We read legal letters from the Company's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated management's judgments related to whether certain insurance recoveries were probable of collection by inquiring of management and the Company's internal legal counsel regarding the amounts of insurance recoveries recorded or disclosed. We obtained and inspected relevant insurance policies to evaluate coverages as well as communication between the Company and insurers.
- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 27, 2025

We have served as the Company's auditor since 2002.

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

	Year Ended Dec. 31		
	2024	2023	2022
Operating revenues			
Electric	$ 11,147	$ 11,446	$ 12,123
Natural gas	2,230	2,645	3,080
Other	64	115	107
Total operating revenues	13,441	14,206	15,310
Operating expenses			
Electric fuel and purchased power	3,788	4,278	5,005
Cost of natural gas sold and transported	951	1,456	1,910
Cost of sales — other	14	49	44
Operating and maintenance expenses	2,540	2,444	2,491
Conservation and demand side management expenses	394	286	331
Depreciation and amortization	2,744	2,448	2,413
Taxes (other than income taxes)	624	657	688
Loss on Comanche Unit 3 litigation	—	35	—
Workforce reduction expenses	—	72	—
Total operating expenses	11,055	11,725	12,882
Operating income	2,386	2,481	2,428
Other income (expense), net	143	22	(13)
Earnings from equity method investments	19	35	36
Allowance for funds used during construction — equity	168	91	75
Interest charges and financing costs			
Interest charges — includes other financing costs	1,255	1,055	953
Allowance for funds used during construction — debt	(73)	(51)	(28)
Total interest charges and financing costs	1,182	1,004	925
Income before income taxes	1,534	1,625	1,601
Income tax benefit	(402)	(146)	(135)
Net income	$ 1,936	$ 1,771	$ 1,736
Weighted average common shares outstanding:			
Basic	563	552	547
Diluted	563	552	547
Earnings per average common share:			
Basic	$ 3.44	$ 3.21	$ 3.18
Diluted	3.44	3.21	3.17

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2024	**2023**	**2022**
Net income	$ 1,936	$ 1,771	$ 1,736
Other comprehensive income			
Pension and retiree medical benefits:			
Net pension and retiree medical (losses) gains arising during the period, net of tax	(3)	(4)	5
Reclassification of losses to net income, net of tax	5	2	4
Derivative instruments:			
Net fair value increase (decrease), net of tax	22	(2)	16
Reclassification of losses to net income, net of tax	2	3	5
Total other comprehensive income (loss)	26	(1)	30
Total comprehensive income	$ 1,962	$ 1,770	$ 1,766

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2024	2023	2022
Operating activities			
Net income	$ 1,936	$ 1,771	$ 1,736
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	2,769	2,471	2,436
Nuclear fuel amortization	106	96	118
Deferred income taxes	225	(59)	(140)
Allowance for equity funds used during construction	(168)	(91)	(75)
Earnings from equity method investments	(19)	(35)	(36)
Dividends from equity method investments	34	35	37
Provision for bad debts	47	79	73
Share-based compensation expense	33	25	20
Changes in operating assets and liabilities:			
Accounts receivable	19	(27)	(429)
Accrued unbilled revenues	21	252	(243)
Inventories	(140)	(98)	(203)
Other current assets	(139)	86	(58)
Accounts payable	37	(149)	195
Net regulatory assets and liabilities	436	911	570
Other current liabilities	(317)	200	102
Pension and other employee benefit obligations	(89)	17	(49)
Other, net	(150)	(157)	(122)
Net cash provided by operating activities	4,641	5,327	3,932
Investing activities			
Capital/construction expenditures	(7,364)	(5,854)	(4,638)
Purchase of investment securities	(998)	(994)	(1,332)
Proceeds from the sale of investment securities	961	959	1,297
Other, net	(27)	(37)	20
Net cash used in investing activities	(7,428)	(5,926)	(4,653)
Financing activities			
Repayments of short-term borrowings, net	(90)	(28)	(192)
Proceeds from issuances of long-term debt	3,647	2,630	2,164
Repayments of long-term debt	(656)	(1,151)	(601)
Proceeds from issuance of common stock	1,117	270	322
Dividends paid	(1,175)	(1,092)	(1,012)
Other, net	(6)	(12)	(15)
Net cash provided by financing activities	2,837	617	666
Net change in cash and cash equivalents	50	18	(55)
Cash, cash equivalents and restricted cash at beginning of period	129	111	166
Cash, cash equivalents and restricted cash at end of period	$ 179	$ 129	$ 111
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (1,131)	$ (945)	$ (887)
Cash received (paid) for income taxes, net; includes proceeds from tax credit transfers	588	92	(15)
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 964	$ 553	$ 626
Inventory transfers to property, plant and equipment	258	197	78
Operating lease right-of-use assets	138	238	141
Allowance for equity funds used during construction	168	91	75
Issuance of common stock for reinvested dividends and/or equity awards	68	64	57

See Notes to Consolidated Financial Statements

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

	Dec. 31 2024	Dec. 31 2023
Assets		
Current assets		
Cash and cash equivalents	$ 179	$ 129
Accounts receivable, net	1,249	1,315
Accrued unbilled revenues	832	853
Inventories	666	711
Regulatory assets	561	611
Derivative instruments	114	104
Prepaid taxes	72	52
Prepayments and other	652	294
Total current assets	4,325	4,069
Property, plant and equipment, net	57,198	51,642
Other assets		
Nuclear decommissioning fund and other investments	3,896	3,599
Regulatory assets	2,849	2,798
Derivative instruments	72	76
Operating lease right-of-use assets	1,060	1,217
Other	635	678
Total other assets	8,512	8,368
Total assets	$ 70,035	$ 64,079
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 1,103	$ 552
Short-term debt	695	785
Accounts payable	1,781	1,668
Regulatory liabilities	852	528
Taxes accrued	535	557
Accrued interest	280	251
Dividends payable	314	289
Derivative instruments	37	74
Operating lease liabilities	227	226
Other	635	722
Total current liabilities	6,459	5,652
Deferred credits and other liabilities		
Deferred income taxes	5,319	4,885
Deferred investment tax credits	40	60
Regulatory liabilities	6,010	5,827
Asset retirement obligations	3,713	3,218
Derivative instruments	77	86
Customer advances	146	167
Pension and employee benefit obligations	477	469
Operating lease liabilities	867	1,038
Other	89	148
Total deferred credits and other liabilities	16,738	15,898
Commitments and contingencies		
Capitalization		
Long-term debt	27,316	24,913
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 574,365,598 and 554,941,703 shares outstanding at Dec. 31, 2024 and Dec. 31, 2023, respectively	1,436	1,387
Additional paid in capital	9,601	8,465
Retained earnings	8,553	7,858
Accumulated other comprehensive loss	(68)	(94)
Total common stockholders' equity	19,522	17,616
Total liabilities and equity	$ 70,035	$ 64,079

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(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
Balance at Dec. 31, 2021	544,025,269	$ 1,360	$ 7,803	$ 6,572	$ (123)	$ 15,612
Net income				1,736		1,736
Other comprehensive income					30	30
Dividends declared on common stock ($1.95 per share)				(1,066)		(1,066)
Issuances of common stock	5,552,749	14	345			359
Share-based compensation			7	(3)		4
Balance at Dec. 31, 2022	549,578,018	$ 1,374	$ 8,155	$ 7,239	$ (93)	$ 16,675
Net Income				1,771		1,771
Other comprehensive loss					(1)	(1)
Dividends declared on common stock ($2.08 per share)				(1,148)		(1,148)
Issuances of common stock	5,363,685	13	295			308
Share-based compensation			15	(4)		11
Balance at Dec. 31, 2023	554,941,703	$ 1,387	$ 8,465	$ 7,858	$ (94)	$ 17,616
Net income				1,936		1,936
Other comprehensive income					26	26
Dividends declared on common stock ($2.19 per share)				(1,236)		(1,236)
Issuances of common stock	19,423,895	49	1,098			1,147
Share-based compensation			38	(5)		33
Balance at Dec. 31, 2024	574,365,598	$ 1,436	$ 9,601	$ 8,553	$ (68)	$ 19,522

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and the regulated purchase, transportation, distribution and sale of natural gas.

Xcel Energy's regulated operations include the activities of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in regulated operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiaries include:

Nonregulated Subsidiary	Purpose
Eloigne	Invests in rental housing projects that qualify for low-income housing tax credits.
Capital Services	Procures equipment for construction of renewable generation facilities at other subsidiaries.
Xcel Energy Venture Holdings, Inc.	Invests in limited partnerships, including funds with portfolios of investments in energy technology companies.
Nicollet Project Holdings	Invests in nonregulated assets such as the Minnesota community solar gardens.

Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries:

Direct Subsidiary
Xcel Energy Wholesale Group Inc.
Xcel Energy Markets Holdings Inc.
Xcel Energy Ventures Inc.
Xcel Energy Retail Holdings Inc.
Xcel Energy Communication Group Inc.
Xcel Energy International Inc.
Xcel Energy Transmission Holding Company, LLC
Nicollet Holdings Company, LLC
Xcel Energy Nuclear Services Holdings, LLC
Xcel Energy Services Inc.

Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated unless a different treatment is appropriate for rate regulated transactions. The equity method of accounting is used for its investments in energy technology funds and WYCO.

Investments in certain plants and transmission facilities are jointly owned with nonaffiliated utilities. A proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's share of operating costs associated with these facilities is included in the consolidated statements of income.

The consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts.

Certain amounts in the consolidated financial statements or notes have been reclassified for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

Xcel Energy has evaluated events occurring after Dec. 31, 2024 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available to record transactions and balances resulting from business operations.

Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations, actuarially determined benefit costs and wildfire contingencies. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — The regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, the utility subsidiaries may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on Xcel Energy's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the consolidated financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets.

Xcel Energy anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of related property. The requirement to defer and amortize these credits specifically applies to certain federal ITCs, as determined by tax regulations and Xcel Energy tax elections. For tax credits otherwise eligible to be recognized when earned, Xcel Energy considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740, *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in the utility subsidiaries' regulatory mechanisms.

Xcel Energy measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties related to income taxes are reported within Other income (expense), net or interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made.

For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Accumulated removal costs are reflected in the consolidated balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.8% for 2024, 3.6% for 2023 and 3.7% for 2022.

See Note 3 for further information.

AROs — Xcel Energy records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are normally performed at least every three years and submitted to the state commissions for approval. The latest decommissioning study was deferred one year and completed in 2024.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Notes 10 and 12 for further information.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 11 for further information.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Estimated future expenditures to restore sites are generally treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability. When separate mechanisms are expected to provide cost recovery or when changes in projected costs occur near the end of a facility's useful life, regulatory accounting may be applied.

See Note 12 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees. The utility subsidiaries recognize physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTO/ISOs are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO/ISO are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — Xcel Energy considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2024 and 2023, the allowance for bad debts was $111 million and $128 million, respectively.

Inventory — Inventory is recorded at the lower of average cost or net realizable value and consisted of the following:

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
Inventories		
Materials and supplies	$ 406	$ 377
Fuel	164	211
Natural gas	96	123
Total inventories	$ 666	$ 711

Equity Method Investments — The equity method of accounting is used for certain investments including WYCO and energy technology funds, which requires Xcel Energy's recognition of its share of these investees' results, based on Xcel Energy's proportional ownership interest. For investments in energy technology funds, this includes Xcel Energy's share of fund expenses and realized gains and losses, as well as unrealized gains and losses resulting from valuations of the funds' investments in emerging energy technology companies.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, rabbi trust assets, commodity derivatives, pension and postretirement plan assets and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For rabbi trust assets, pension and postretirement plan assets and nuclear decommissioning fund assets, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for purchases and sales of commodities for use and sale in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

See Note 10 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 10 for further information.

Other Utility Items

AFUDC **—** AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base.

Alternative Revenue **—** Certain rate rider mechanisms (including decoupling/sales true up and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs **—** Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emissions Allowances **—** Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs **—** Xcel Energy uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

RECs **—** Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel and purchased power costs for the cost of RECs received.

An inventory accounting model is used to account for RECs, however these assets are classified as regulatory assets if amounts are recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are presented on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

Recently Adopted

Segment Reporting **—** In November 2023, the FASB issued ASU 2023-07 – *Segment Reporting (Topic 280) – Improvements to Reportable Segment Disclosures*, which extends the existing requirements for annual disclosures to quarterly periods, and requires that both annual and quarterly disclosures present segment expenses using line items consistent with information regularly provided to the chief operating decision maker. Xcel Energy implemented this guidance on a retrospective basis in the year ended Dec. 31, 2024. The adoption impacts were not material.

See Note 14 for further information.

Recently Issued

Income Taxes **—** In December 2023, the FASB issued ASU 2023-09 – *Income Taxes (Topic 740) – Improvements to Income Tax Disclosures*, with new disclosure requirements including presentation of prescribed line items in the ETR reconciliation and disclosures regarding state and local tax payments. The ASU is effective for annual periods beginning after Dec. 15, 2024, and Xcel Energy does not expect implementation of the new disclosure guidance to have a material impact on its consolidated financial statements.

Climate-Related Disclosures **—** In March 2024, the SEC issued Final Rule 33-11275 – The Enhancement and Standardization of Climate-Related Disclosures for Investors. This rule requires registrants to provide standardized disclosures in Form 10-K related to climate-related risks, Scope 1 and 2 GHG emissions, as well as to include in a footnote to the consolidated financial statements the financial impact of severe weather events and other natural conditions. The rule requires implementation in phases between 2025 and 2033. In April 2024, the SEC announced that it would voluntarily stay its final climate disclosure rules pending judicial review. Xcel Energy does not expect the potential implementation of the new guidance to have a material impact on the consolidated financial statements.

Disaggregation of Income Statement Expenses **—** In November 2024, the FASB issued ASU 2024-03 – *Disaggregation of Income Statement Expenses*, which requires disaggregated disclosure of income statement expenses for public business entities. The ASU is effective for annual periods beginning after Dec. 15, 2026. Xcel Energy is currently evaluating the impact of implementing the new disclosure guidance.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
Property, plant and equipment, net		
Electric plant	$ 56,791	$ 52,494
Natural gas plant	9,834	9,080
Common and other property	3,515	3,190
Plant to be retired [(a)]	1,793	2,055
CWIP	4,720	2,873
Total property, plant and equipment	76,653	69,692
Less accumulated depreciation	(19,852)	(18,399)
Nuclear fuel	3,491	3,337
Less accumulated amortization	(3,094)	(2,988)
Property, plant and equipment, net	$ 57,198	$ 51,642

(a) Amounts include Sherco 1 and 3 and A.S. King for NSP-Minnesota; Comanche Units 2 and 3, Craig Units 1 and 2, Hayden Units 1 and 2 and coal generation assets at Pawnee pending facility gas conversion for PSCo; and Tolk Unit 1 and 2 for SPS. The Dec. 31, 2023 amounts also include coal generation assets at Harrington, which were retired in 2024 and the conversion to natural gas is in process. Amounts are presented net of accumulated depreciation.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2024:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Minnesota			
Electric generation:			
Sherco Unit 3	$ 636	$ 499	59 %
Sherco common facilities	189	128	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	4	50
Huntley Wilmarth	49	3	50
CapX2020	855	160	51
Total NSP-Minnesota [(a)]	$ 1,745	$ 798	

(a) Projects additionally include $10 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Wisconsin			
Electric transmission:			
La Crosse, WI to Madison, WI	$ 179	$ 30	37 %
CapX2020	169	44	80
Total NSP-Wisconsin [(a)]	$ 348	$ 74	

(a) Projects additionally include $1 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
PSCo			
Electric generation:			
Hayden Unit 1	$ 158	$ 117	76 %
Hayden Unit 2	152	93	37
Hayden common facilities	45	33	53
Craig Units 1 and 2	82	58	10
Craig common facilities	40	27	7
Comanche Unit 3	933	212	67
Comanche common facilities	29	5	77
Electric transmission:			
Transmission and other facilities	190	75	Various
Gas transmission:			
Rifle, CO to Avon, CO	28	10	60
Gas transmission compressor	8	3	50
Total PSCo [(a)]	$ 1,665	$ 633	

(a) Projects additionally include $28 million in CWIP.

Each company separately records its share of operating expenses and construction expenditures. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2024		Dec. 31, 2023	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 39	$ 1,167	$ 27	$ 1,106
Net AROs	1, 12	Various	—	387	—	316
Recoverable deferred taxes on AFUDC		Plant lives	—	368	—	332
Depreciation differences		Various	17	250	17	189
Excess deferred taxes — TCJA	7	Various	10	184	10	198
MISO capacity revenue tracker		One to two years	63	45	36	26
Environmental remediation costs	1, 12	Various	13	39	15	94
Prairie Island extended power uprate		10 years	4	34	4	38
Conservation programs [(a)]	1	One to two years	20	30	19	54
Purchased power contract costs		Term of related contract	5	28	4	40
Benson biomass PPA termination and asset purchase		Four years	10	26	10	36
Deferred natural gas, electric, steam energy/fuel costs		One to two years	99	25	239	80
Sales true-up and revenue decoupling		Various	60	23	7	33
Nuclear refueling outage costs	1	One to two years	51	20	43	19
Gas pipeline inspection and remediation costs		One to two years	47	9	40	25
Renewable resources and environmental initiatives		One to two years	34	4	38	5
Other		Various	89	210	102	207
Total regulatory assets			$ 561	$ 2,849	$ 611	$ 2,798

(a) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2024		Dec. 31, 2023	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 7	$ 2,888	$ 7	$ 3,015
Plant removal costs	1, 12	Various	—	2,208	—	1,984
Effects of regulation on employee benefit costs [(b)]	11	Various	—	259	—	253
Renewable resources and environmental initiatives		Various	16	232	9	188
Net AROs [(c)]		Various	—	161	—	90
ITC deferrals	1	Various	—	70	1	60
IRA deferral		One to three years	3	37	—	—
Deferred natural gas, electric, steam energy/fuel costs		One to two years	480	12	220	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	89	—	56	—
Conservation programs [(e)]	1	Less than one year	52	—	47	—
Other		Various	205	143	188	237
Total regulatory liabilities [(f)]			$ 852	$ 6,010	$ 528	$ 5,827

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.
(b) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.
(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(d) Includes the fair value of FTR instruments utilized/intended to offset the impacts of transmission system congestion.
(e) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions..
(f) Revenue subject to refund of $3 million and $187 million for 2024 and 2023, respectively, is included in other current liabilities.

Xcel Energy's regulatory assets not earning a return include past expenditures of $892 million and $1,085 million at Dec. 31, 2024 and 2023 respectively, which predominately relate to purchased natural gas and electric energy costs (including certain costs related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts. Additionally, the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed) do not earn a return.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facilities and term loan agreements.

Commercial paper and other borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2024	Year Ended Dec. 31 2024	2023	2022
Borrowing limit	$ 3,550	$ 3,550	$ 3,550	$ 3,550
Amount outstanding at period end	695	695	785	813
Average amount outstanding	133	508	491	552
Maximum amount outstanding	695	1,314	1,241	1,357
Weighted average interest rate, computed on a daily basis	4.77 %	5.47 %	5.12 %	1.47 %
Weighted average interest rate at period end	4.64	4.64	5.52	4.66

Bilateral Credit Agreement — In April 2024, 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 Dec. 31, 2024, NSP-Minnesota had $74 million outstanding letters of credit under the $75 million Bilateral Credit Agreement.

Letters of Credit — Xcel Energy uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2024 and 2023, there were $42 million and $44 million of letters of credit outstanding under the credit facilities, respectively. Amounts approximate their fair value.

Credit Facilities — In order to use commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities.

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.

In September 2022, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each entered into an amended five-year credit agreement with a syndicate of banks. The aggregate borrowing limit is $3.55 billion. The amended credit agreements mature in September 2027.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio (a) 2024	2023	Amount Facility May Be Increased (millions of dollars) (b)	Additional Periods for Which a One-Year Extension May Be Requested (c)
Xcel Energy Inc. (d)	59.8 %	59.8 %	$ 350	2
NSP-Minnesota	47.0	47.7	150	2
NSP-Wisconsin	47.1	48.2	N/A	1
SPS	46.6	46.1	50	2
PSCo	45.2	44.8	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
(b) Amounts authorized by state commissions in respective jurisdictions.
(c) All extension requests are subject to majority bank group approval.
(d) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. would be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2024, Xcel Energy Inc. and its subsidiaries were in compliance with the financial covenant.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2024:

(Millions of Dollars)	Credit Facility (a)	Drawn (b)	Available
Xcel Energy Inc.	$ 1,500	$ 235	$ 1,265
PSCo	700	115	585
NSP-Minnesota	700	207	493
SPS	500	145	355
NSP-Wisconsin	150	35	115
Total	$ 3,550	$ 737	$ 2,813

(a) These credit facilities mature in September 2027.
(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its utility subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2024 and 2023.

Long-Term Borrowings and Other Financing Instruments

Generally, the property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS is subject to the liens of their respective first mortgage indentures for the benefit of bondholders.

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31 (in millions of dollars, except interest rates):

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2024	2023
Unsecured senior notes	3.30 %	June 1, 2025	250	250
Unsecured senior notes	3.30	June 1, 2025	350	350
Unsecured senior notes	3.35	Dec. 1, 2026	500	500
Unsecured senior notes	1.75	March 15, 2027	500	500
Unsecured senior notes	4.00	June 15, 2028	130	130
Unsecured senior notes	4.00	June 15, 2028	500	500
Unsecured senior notes	2.60	Dec. 1, 2029	500	500
Unsecured senior notes	3.40	June 1, 2030	600	600
Unsecured senior notes	2.35	Nov. 15, 2031	300	300
Unsecured senior notes	4.60	June 1, 2032	700	700
Unsecured senior notes [(a)]	5.45	Aug. 15, 2033	800	800
Unsecured senior notes [(b)]	5.50	March 15, 2034	800	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sept. 15, 2041	250	250
Unsecured senior notes	3.50	Dec. 1, 2049	500	500
Unamortized discount			(9)	(8)
Unamortized debt issuance cost			(34)	(36)
Current maturities			(600)	—
Total long-term debt			$ 6,337	$ 6,136

(a) 2023 financing.
(b) 2024 financing.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2024	2023
First mortgage bonds	7.125 %	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds	2.25	April 1, 2031	425	425
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds	2.60	June 1, 2051	700	700
First mortgage bonds	3.20	April 1, 2052	425	425
First mortgage bonds	4.50	June 1, 2052	500	500
First mortgage bonds [(a)]	5.10	May 15, 2053	800	800
First mortgage bonds [(b)]	5.40	March 15, 2054	700	—
Other long-term debt			2	2
Long-term debt — related parties principal amount outstanding	2.60	Jun 1, 2051	(166)	—
Unamortized discount			(49)	(49)
Unamortized debt issuance cost			(80)	(73)
Current maturities			(250)	—
Total long-term debt			$ 7,607	$ 7,330

(a) 2023 financing.
(b) 2024 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2024	2023
First mortgage bonds	3.30 %	June 15, 2024	$ —	$ 100
First mortgage bonds	3.30	June 15, 2024	—	100
First mortgage bonds	6.375	Sept. 1, 2038	200	200
First mortgage bonds	3.70	Oct. 1, 2042	100	100
First mortgage bonds	3.75	Dec. 1, 2047	100	100
First mortgage bonds	4.20	Sept. 1, 2048	200	200
First mortgage bonds	3.05	May 1, 2051	100	100
First mortgage bonds	2.82	May 1, 2051	100	100
First mortgage bonds	4.86	Sept. 15, 2052	100	100
First mortgage bonds [(a)]	5.30	June 15, 2053	125	125
First mortgage bonds [(b)]	5.65	June 15, 2054	400	—
Unamortized discount			(4)	(3)
Unamortized debt issuance cost			(15)	(11)
Current maturities			—	(200)
Total long-term debt			$ 1,406	$ 1,011

(a) 2023 financing.
(b) 2024 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2024	2023
First mortgage bonds	2.90 %	May 15, 2025	250	250
First mortgage bonds	3.70	June 15, 2028	350	350
First mortgage bonds	1.90	Jan. 15, 2031	375	375
First mortgage bonds	1.875	June 15, 2031	750	750
First mortgage bonds	4.10	June 1, 2032	300	300
First mortgage bonds [(a)]	5.35	May 15, 2034	450	—
First mortgage bonds	6.25	Sept. 1, 2037	350	350
First mortgage bonds	6.50	Aug. 1, 2038	300	300
First mortgage bonds	4.75	Aug. 15, 2041	250	250
First mortgage bonds	3.60	Sept. 15, 2042	500	500
First mortgage bonds	3.95	March 15, 2043	250	250
First mortgage bonds	4.30	March 15, 2044	300	300
First mortgage bonds	3.55	June 15, 2046	250	250
First mortgage bonds	3.80	June 15, 2047	400	400
First mortgage bonds	4.10	June 15, 2048	350	350
First mortgage bonds	4.05	Sept. 15, 2049	400	400
First mortgage bonds	3.20	March 1, 2050	550	550
First mortgage bonds	2.70	Jan. 15, 2051	375	375
First mortgage bonds	4.50	June 1, 2052	400	400
First mortgage bonds [(b)]	5.25	April 1, 2053	850	850
First mortgage bonds [(a)]	5.75	May 15, 2054	750	—
Unamortized discount			(42)	(41)
Unamortized debt issuance cost			(67)	(59)
Current maturities			(250)	—
Total long-term debt			$ 8,391	$ 7,450

(a) 2024 financing.
(b) 2023 financing.

SPS				
Financing Instrument	Interest Rate	Maturity Date	2024	2023
First mortgage bonds	3.30 %	June 15, 2024	$ —	$ 150
First mortgage bonds	3.30	June 15, 2024	—	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds	4.40	Nov. 15, 2048	300	300
First mortgage bonds	3.75	June 15, 2049	300	300
First mortgage bonds	3.15	May 1, 2050	350	350
First mortgage bonds	3.15	May 1, 2050	250	250
First mortgage bonds	5.15	June 1, 2052	200	200
First mortgage bonds [(a)]	6.00	Sept. 15, 2053	100	100
First mortgage bonds [(b)]	6.00	June 1, 2054	600	—
Unamortized discount			(14)	(10)
Unamortized debt issuance cost			(35)	(29)
Current maturities			—	(350)
Total long-term debt			$ 3,551	$ 2,961

(a) 2023 financing.
(b) 2024 financing.

Other Subsidiaries				
Financing Instrument	Interest Rate	Maturity Date	2024	2023
Various Eloigne affordable housing project notes	0.00% - 8.00%	2024 - 2055	$ 27	$ 27
Current maturities			(3)	(2)
Total long-term debt			$ 24	$ 25

Maturities of long-term debt:

(Millions of Dollars)	
2025	$ 1,103
2026	501
2027	501
2028	1,133
2029	503

Xcel Energy Inc.'s Purchase of NSP-Minnesota's First Mortgage Bonds — During 2024, Xcel Energy Inc. purchased $166 million in aggregate principal amounts of NSP-Minnesota's 2.60% First Mortgage Bonds Series due June 1, 2051 for $105 million. On a consolidated basis, Xcel Energy Inc.'s repurchase of NSP-Minnesota first mortgage bonds was accounted for as a debt extinguishment and resulted in a pre-tax gain of approximately $56 million, net of unamortized discount and debt issuance costs. Interest expense related to the repurchased bonds was immaterial for the year ended Dec. 31, 2024.

Deferred Financing Costs — Deferred financing costs of approximately $235 million and $209 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2024 and 2023, respectively.

Equity through DRIP and Benefits Program — Xcel Energy issued $67 million of equity in 2024 and $88 million of equity in 2023 through the DRIP and benefits programs. The program allows shareholders to reinvest their dividends directly in Xcel Energy Inc. common stock.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. In 2022, 4.3 million shares of common stock were issued (approximately $300 million in net proceeds and $3 million in transaction fees paid). In 2023, 0.9 million shares of common stock were issued ($62 million in net proceeds and $1 million in transaction fees paid). In October 2023, the 2021 ATM offering was closed.

In October 2023, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $2.5 billion of its common stock through an ATM program. In 2023, through this ATM program, Xcel Energy Inc. issued 3.1 million shares of common stock ($188 million in net proceeds and $2 million in transaction fees paid). In 2024, 18.3 million shares of common stock were issued ($1.1 billion in net proceeds and $9 million in transaction fees paid).

Forward Equity Agreements — In November 2024, Xcel Energy Inc. entered into forward sale agreements in connection with completed public offerings of 21.1 million shares of Xcel Energy common stock. The initial forward agreements were for 18.3 million shares with additional agreements for 2.8 million shares exercised at the option of the banking counterparties.

At Dec. 31, 2024, the forward agreements could have been settled with physical delivery of 21.1 million common shares to the banking counterparties in exchange for cash of $1.37 billion. The agreements could also have been settled at Dec. 31, 2024 with delivery of approximately $94 million of cash or approximately 1.4 million shares of common stock to the banking counterparties, if Xcel Energy unilaterally elected net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2024 public offering price of $64.44 (net of underwriting fees), increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the agreements are outstanding.

Xcel Energy may settle the forward agreements at any time up to the maturity date of June 30, 2026. The cash proceeds, depending on the timing of future settlement, are expected to be approximately $1.36 billion.

As initial pricing terms were based on market prices for Xcel Energy common stock, no amounts were recorded at the execution of the forward agreements. Stockholders' equity equal to cash proceeds will be recorded at settlement.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2024 and 2023
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

Xcel Energy Inc. had the following common stock authorized/outstanding:

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) as of Dec. 31, 2024	Common Stock Outstanding (Shares) as of Dec. 31, 2023
1,000,000,000	$ 2.50	574,365,598	554,941,703

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its utility subsidiaries to pay dividends. Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. Certain covenants also require Xcel Energy Inc. to be current on interest payments prior to dividend disbursements.

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2024:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2024
NSP-Minnesota	47.6 %	58.2 %	53.0 %
NSP-Wisconsin [(a)]	52.5	N/A	52.7
SPS [(b)]	45.0	55.0	54.4

(a) Cannot pay annual dividends in excess of forecasted levels if its average equity-to-total capitalization ratio falls below the commission authorized level.

(b) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,809	$ 17,490	$ 17,800
NSP-Wisconsin	12	2,922	N/A
SPS [(a)]	592	7,789	N/A

(a) May not pay a dividend that would cause a loss of its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. is not generally subject to regulatory approval. However, utility financings and intra-system financings are subject to the jurisdiction of state regulatory commissions and/or the FERC. Xcel Energy may seek additional authorization as necessary.

Amounts authorized to issue as of Dec. 31, 2024:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota [(a)]	52.4% of total capitalization	$ 2,670
NSP-Wisconsin	$ 225	150
PSCo	1,300	1,200
SPS	150	700

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.

6. Revenues

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

	Year Ended Dec. 31, 2024			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,552	$ 1,299	$ 11	$ 4,862
C&I	5,420	646	30	6,096
Other	142	—	9	151
Total retail	9,114	1,945	50	11,109
Wholesale	645	—	—	645
Transmission	648	—	—	648
Other	64	175	—	239
Total revenue from contracts with customers	10,471	2,120	50	12,641
Alternative revenue and other	676	110	14	800
Total revenues	$ 11,147	$ 2,230	$ 64	$ 13,441

	Year Ended Dec. 31, 2023			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,560	$ 1,560	$ 59	$ 5,179
C&I	5,703	833	30	6,566
Other	150	—	13	163
Total retail	9,413	2,393	102	11,908
Wholesale	815	—	—	815
Transmission	649	—	—	649
Other	63	156	—	219
Total revenue from contracts with customers	10,940	2,549	102	13,591
Alternative revenue and other	506	96	13	615
Total revenues	$ 11,446	$ 2,645	$ 115	$ 14,206

	Year Ended Dec. 31, 2022			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,542	$ 1,814	$ 53	$ 5,409
C&I	5,807	998	32	6,837
Other	148	—	10	158
Total retail	9,497	2,812	95	12,404
Wholesale	1,354	—	—	1,354
Transmission	675	—	—	675
Other	97	178	—	275
Total revenue from contracts with customers	11,623	2,990	95	14,708
Alternative revenue and other	500	90	12	602
Total revenues	$ 12,123	$ 3,080	$ 107	$ 15,310

7. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2024	2023	2022
leral statutory rate	21.0 %	21.0 %	21.0 %
e income tax on pretax income, net of federal tax effect	4.8	4.9	4.9
creases) increases in tax from:			
TCs [a]	(43.2)	(28.1)	(27.4)
lant regulatory differences [b]	(7.3)	(5.6)	(5.5)
ther tax credits, net NOL & tax credit allowances	(1.3)	(1.3)	(1.3)
ther, net	(0.2)	0.1	(0.1)
ctive income tax rate	(26.2)%	(9.0)%	(8.4)%

(a) Wind, Solar and Nuclear PTCs (net of estimated transfer discounts) are generally credited to customers (reduction to revenue) and do not materially impact earnings. Nuclear PTCs, newly available in 2024, resulted in benefits of 11.3% to the ETR for the year ended Dec. 31, 2024.
(b) Plant regulatory differences primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit are offset by corresponding revenue reductions.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2024	2023	2022
Current federal tax expense	$ 36	$ 113	$ 1
Current state tax expense	28	16	3
Current change in unrecognized tax expense (benefit)	2	(21)	5
Deferred federal tax benefit	(510)	(331)	(239)
Deferred state tax expense	46	75	96
Deferred change in unrecognized tax expense	—	7	3
Deferred ITCs	(4)	(5)	(4)
Total income tax benefit	$ (402)	$ (146)	$ (135)

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2024	2023	2022
Deferred tax expense (benefit) excluding items below	$ 434	$ 129	$ (138)
Adjustments to deferred income taxes for tax credit cash transfers [a]	(689)	(190)	—
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(201)	(188)	8
Tax expense allocated to other comprehensive income and other	(8)	—	(10)
Deferred tax benefit	$ (464)	$ (249)	$ (140)

(a) Proceeds from tax credit transfers are included in cash received (paid) for income taxes in the consolidated statement of cash flows.

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2024	2023 [a]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 7,008	$ 6,744
Regulatory assets	566	523
Operating lease assets	282	327
Pension expense	155	151
Deferred fuel costs	—	67
Other	97	80
Total deferred tax liabilities	$ 8,108	$ 7,892
Deferred tax assets:		
Tax credit carryforward	$ 1,589	$ 1,718
Regulatory liabilities	751	715
Operating lease liabilities	282	327
Other employee benefits	102	117
Deferred ITCs	11	16
NOL carryforward	1	—
NOL and tax credit valuation allowances	(73)	(70)
Other	126	184
Total deferred tax assets	2,789	3,007
Net deferred tax liability	$ 5,319	$ 4,885

(a) Prior periods have been reclassified to conform to current year presentation.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31:

(Millions of Dollars)	2024	2023
Federal tax credit carryforwards	$ 1,519	$ 1,644
Valuation allowances for federal credit carryforwards	(14)	(10)
State NOL carryforwards	9	11
Valuation allowances for state NOL carryforwards	(2)	(2)
State tax credit carryforwards, net of federal detriment [a]	70	74
Valuation allowances for state credit carryforwards, net of federal benefit [b]	(58)	(60)

(a) State tax credit carryforwards are net of federal detriment of $19 million and $20 million as of Dec. 31, 2024 and 2023, respectively.
(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $16 million as of Dec. 31, 2024 and 2023.

Federal carryforward periods expire between 2038 and 2044. State carryforward periods, not including those with indefinite carryforward periods, expire between 2025 and 2037.

Unrecognized Tax Benefits

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

Tax Year(s)	Expiration
2014 - 2016	March 2025
2021	October 2025

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. In 2023 the IRS issued its Revenue Agent's Report related to the federal tax loss carryback claim. The Company materially agreed with the report and re-recognized the related benefit in 2023.

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 Dec. 31, 2024, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Tax Year(s)	Expiration
Colorado	2014 - 2016	March 2026
Colorado	2020	September 2025
Minnesota	2014 - 2016	September 2025
Minnesota	2020	June 2025
Texas	2016 - 2019	December 2025
Wisconsin	2016 - 2019	May 2025
Wisconsin	2020	September 2025

- In 2021, Texas began an audit of tax years 2016 - 2019. As of Dec. 31, 2024, no material adjustments have been proposed.
- In 2021, Wisconsin began an audit of tax years 2016-2019. As of Dec. 31, 2024, no material adjustments have been proposed.
- No other state income tax audits are in progress for its major operating jurisdictions as of Dec. 31, 2024.

Unrecognized tax benefit balance may include permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance may include temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the period 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)	Dec. 31, 2024	Dec. 31, 2023
Unrecognized tax benefit — Permanent tax positions	$ 43	$ 41
Unrecognized tax benefit — Temporary tax positions	—	—
Total unrecognized tax benefit	$ 43	$ 41

Changes in unrecognized tax benefits:

(Millions of Dollars)	2024	2023	2022
Balance at Jan. 1	$ 41	$ 67	$ 58
Additions based on tax positions related to the current year	5	5	7
Additions for tax positions of prior years	2	1	6
Reductions for tax positions of prior years	(3)	(29)	(1)
Reductions for tax positions related to settlements with taxing authorities	—	(1)	(1)
Reductions for tax positions related to statute of limitations	(2)	(2)	(2)
Balance at Dec. 31	$ 43	$ 41	$ 67

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

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
NOL and tax credit carryforwards	$ (35)	$ (35)

As state audits progress, it is reasonably possible that the amount of current liabilities related to unrecognized tax benefits could decrease up to approximately $2 million in the next 12 months. Additionally, there exists approximately $41 million of noncurrent liabilities related to unrecognized tax benefits for which there is uncertainty about if or when these liabilities will significantly increase or decrease.

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)	2024	2023	2022
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (1)	$ (4)	$ (3)
Interest (expense) benefit related to unrecognized tax benefits	(1)	3	(1)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (2)	$ (1)	$ (4)

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2024, 2023 or 2022.

8. Share-Based Compensation

Incentive Plan Including Share-Based Compensation — Xcel Energy has authorized 13.0 million equity shares under the Xcel Energy Inc. 2024 Equity Incentive Plan for grants made on May 22, 2024 or later and 6.0 million equity shares under the Amended and Restated 2015 Omnibus Incentive Plan for grants made prior to May 22, 2024.

Equity Awards — Xcel Energy's Board of Directors has granted equity awards under the 2024 Equity Incentive Plan and 2015 Omnibus Incentive Plan, determined by grant date, which includes various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. The total time-based equity shares granted subject only to service conditions was 0.5 million in 2024, 0.4 million in 2023 and 0.2 million in 2022.

The performance conditions for a portion of the awards granted from 2022 to 2024 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled after three years, with payouts ranging from zero to 200% depending on achievement.

Equity award units granted to employees:

(Units in Thousands)	2024	2023	2022
Granted units	658	586	395
Weighted average grant date fair value	$ 63.02	$ 67.06	$ 68.43

Equity awards vested:

(Units in Thousands, Fair Value in Millions)	2024	2023	2022
Vested Units	282	329	319
Total Fair Value	$ 19	$ 20	$ 22

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2024	819	$ 67.36
Granted	658	63.02
Forfeited	(111)	66.77
Vested	(282)	68.58
Dividend equivalents	55	66.16
Nonvested Units at Dec. 31, 2024	1,139	64.55

Stock Equivalent Units — Non-employee members of Xcel Energy's Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2024	2023	2022
Granted units	44	38	29
Weighted average grant date fair value	$ 57.03	$ 63.12	$ 71.97

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2024	517	$ 46.07
Granted	44	57.03
Units distributed	(52)	33.19
Dividend equivalents	19	58.15
Stock equivalent units at Dec. 31, 2024	528	48.68

Liability Awards — Xcel Energy's Board of Directors has granted TSR liability awards under the 2024 Equity Incentive Plan and 2015 Omnibus Incentive Plan, determined by grant date. These plans allow Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a peer group of other utility companies. Potential payouts of the awards range from zero to 200%.

Liability awards granted:

(In Thousands)	2024	2023	2022
Awards granted	193	216	165

Liability awards settled:

(Units In Thousands, Settlement Amount in Millions)	2024	2023	2022
Awards settled	—	282	411
Settlement amount (cash, common stock and deferred amounts)	$ —	$ 19	$ 27

There were no TSR liability awards settled in 2024.

Share-Based Compensation Expense — Award settlement determination (permitting cash or share settlement) is made by Xcel Energy, not the participants. Equity awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. Grant date fair value of equity awards is expensed over the service period.

TSR liability awards are accounted for as liabilities, as historically they are partially settled in cash. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the award on the settlement date.

Compensation costs related to share-based awards:

(Millions of Dollars)	2024	2023	2022
Cost for share-based awards [(a)]	$ 30	$ 27	$ 36
Tax benefit recognized in income	8	7	9

(a) Compensation costs for share-based payments are included in O&M expense. Amount for equity awards (non-cash) was $33 million, $25 million and $20 million in 2024, 2023 and 2022, respectively.

There was approximately $38 million as of both Dec. 31, 2024 and 2023, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.7 years.

9. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average 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 — Common stock equivalents include commitments to issue common stock related to forward equity agreements and time-based equity compensation awards.

Stock equivalent units granted to Xcel Energy's Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition following the grant of these awards. Restricted stock issued to employees under the Executive Annual Incentive Award Plan 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 for settlement 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:

(Shares in Millions)	2024	2023	2022
Basic	563	552	547
Diluted [(a)]	563	552	547

(a) Diluted common shares outstanding included common stock equivalents of 0.5 million, 0.3 million, and 0.3 million shares for 2024, 2023 and 2022, respectively.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

- 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 actively traded instruments with observable actual trading prices.
- Level 2 — Pricing inputs are other than actual trading 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 include those valued with models requiring significant judgment or estimation.

Specific valuation methods include:

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 funds 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 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 contracts relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges, 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 an 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 values of these instruments are derived from, and designed to offset, the costs 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 these instruments.

FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3 classification.

Net congestion costs, including the impact of FTR settlements, are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

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 investment targets by asset class for the 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 or as a regulatory liability (dependent on funding status) 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/liability.

Unrealized gains for the nuclear decommissioning fund were $1.4 billion and $1.2 billion as of Dec. 31, 2024 and 2023, respectively, and unrealized losses were $49 million and $29 million as of Dec. 31, 2024 and 2023, respectively.

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

	Dec. 31, 2024					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 39	$ 39	$ —	$ —	$ —	$ 39
Commingled funds	703	—	—	—	1,025	1,025
Debt securities	866	—	832	14	—	846
Equity securities	522	1,583	1	—	—	1,584
Total	$ 2,130	$ 1,622	$ 833	$ 14	$ 1,025	$ 3,494

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $246 million of equity method investments and $156 million of rabbi trust assets and other miscellaneous investments.

(Millions of Dollars)	Dec. 31, 2023 Cost	Fair Value Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$ 41	$ 41	$ —	$ —	$ —	$ 41
Commingled funds	721	—	—	—	1,049	1,049
Debt securities	784	—	771	9	—	780
Equity securities	508	1,339	2	—	—	1,341
Total	$ 2,054	$ 1,380	$ 773	$ 9	$ 1,049	$ 3,211

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $244 million of equity investments in unconsolidated subsidiaries and $144 million of rabbi trust assets and other miscellaneous investments.

For the years ended Dec. 31, 2024 and 2023, 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 Dec. 31, 2024:

(Millions of Dollars)	Final Contractual Maturity 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	$ 7	$ 308	$ 269	$ 262	$ 846

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future deferred compensation plan distributions. The fair value of assets held in the rabbi trusts were $96 million and $88 million at Dec. 31, 2024 and 2023, respectively, comprised of cash equivalents and mutual funds (level 1 valuation methods). Amounts are reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Activities and 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, and utility commodity prices.

Interest Rate Derivatives — Xcel Energy enters into contracts that effectively fix the interest rate on a specified principal amount of a hypothetical future debt issuance. These financial swaps net settle based on changes in a specified benchmark interest rate, acting as a hedge of changes in market interest rates that will impact specified anticipated debt issuances. These derivative instruments are designated as cash flow hedges for accounting purposes, with changes in fair value prior to occurrence of the hedged transactions recorded as other comprehensive income.

As of Dec. 31, 2024, accumulated other comprehensive loss related to interest rate derivatives included $2 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2024, Xcel Energy had no unsettled interest rate swaps outstanding.

See Note 13 for the financial impact of qualifying interest rate cash flow hedges on Xcel Energy's accumulated other comprehensive loss included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income.

Wholesale and Commodity Trading — 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.

Results of derivative instrument transactions entered into for trading purposes are presented in the consolidated statements of income as electric revenues, net of any sharing with customers. These activities are not intended to mitigate commodity price risk associated with regulated electric and natural gas operations. Sharing of these 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. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and FTRs.

The most significant derivative positions outstanding at Dec. 31, 2024 and 2023 for this purpose relate to FTR instruments administered by MISO and SPP. These instruments are intended to offset the impacts of transmission system congestion.

When Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

As of Dec. 31, 2024, Xcel Energy had no commodity contracts designated as cash flow hedges.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [a][b]	Dec. 31, 2024	Dec. 31, 2023
MWh of electricity	38	48
MMBtu of natural gas	77	84

(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 on the consolidated balance sheets.

Xcel Energy's utility subsidiaries' often have significant concentrations of credit risk with particular entities or industries in their wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2024, three of Xcel Energy's ten most significant counterparties for these activities, comprising $34 million or 18% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings.

Six of the ten most significant counterparties, comprising $74 million or 40% 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.

One of these significant counterparties, comprising $43 million or 23% of this credit exposure, had credit quality less than investment grade, based on internal analysis.

Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and 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.

As of Dec. 31, 2024 and 2023, there were $11 million and $12 million, respectively, of derivative liabilities with such underlying contract provisions, respectively.

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 Dec. 31, 2024 and 2023, there were approximately $69 million and $88 million of derivative liabilities with such underlying contract provisions, respectively.

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 Dec. 31, 2024 and 2023.

Recurring Derivative Fair Value Measurements

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	**Accumulated Other Comprehensive Loss**	**Regulatory (Assets) and Liabilities**
Year Ended Dec. 31, 2024		
Derivatives designated as cash flow hedges		
Interest rate	$ 29	$ —
Total	$ 29	$ —
Other derivative instruments		
Electric commodity	$ —	$ 44
Natural gas commodity	—	4
Total	$ —	$ 48
Year Ended Dec. 31, 2023		
Interest rate	$ (2)	$ —
Total	$ (2)	$ —
Other derivative instruments		
Electric commodity	$ —	$ (137)
Natural gas commodity	—	(13)
Total	$ —	$ (150)
Year Ended Dec. 31, 2022		
Interest rate	$ 22	$ —
Total	$ 22	$ —
Other derivative instruments		
Electric commodity	$ —	$ (10)
Natural gas commodity	—	(16)
Total	$ —	$ (26)

(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
Year Ended Dec. 31, 2024			
Derivatives designated as cash flow hedges			
Interest rate	$ 3 [a]	$ —	$ —
Total	$ 3	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (27) [b]
Electric commodity	—	(22) [c]	—
Natural gas commodity	—	—	(22) [d][e]
Total	$ —	$ (22)	$ (49)
Year Ended Dec. 31, 2023			
Derivatives designated as cash flow hedges			
Interest rate	$ 5 [a]	$ —	$ —
Total	$ 5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (7) [b]
Electric commodity	—	123 [c]	—
Natural gas commodity	—	15 [d]	(27) [d][e]
Total	$ —	$ 138	$ (34)
Year Ended Dec. 31, 2022			
Derivatives designated as cash flow hedges			
Interest rate	$ 7 [a]	$ —	$ —
Total	$ 7	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 25 [b]
Electric commodity	—	3 [c]	—
Natural gas commodity	—	10 [d]	(27) [d][e]
Total	$ —	$ 13	$ (2)

(a) Recorded to interest charges.
(b) Recorded to electric revenues. Presented amounts do not reflect non-derivative transactions or margin sharing with customers.
(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. FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.
(d) Other than $3 million of 2024 losses recorded to electric fuel and purchased power, amounts are recorded to cost of natural gas sold and transported. Amounts are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.
(e) Relates primarily to option premium amortization.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2024, 2023 and 2022.

Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2024						Dec. 31, 2023					
	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												
Other derivative instruments:												
Commodity trading	$ 6	$ 20	$ 8	$ 34	$ (23)	$ 11	$ 8	$ 51	$ 32	$ 91	$ (59)	$ 32
Electric commodity	—	—	90	90	(1)	89	—	—	62	62	(7)	55
Natural gas commodity	—	14	—	14	—	14	—	14	—	14	—	14
Total current derivative assets	$ 6	$ 34	$ 98	$ 138	$ (24)	114	$ 8	$ 65	$ 94	$ 167	$ (66)	101
PPAs [(b)]						—						3
Current derivative instruments						$ 114						$ 104
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 8	$ 37	$ 47	$ 92	$ (20)	$ 72	$ 14	$ 51	$ 45	$ 110	$ (34)	$ 76
Total noncurrent derivative assets	$ 8	$ 37	$ 47	$ 92	$ (20)	$ 72	$ 14	$ 51	$ 45	$ 110	$ (34)	$ 76

	Dec. 31, 2024						Dec. 31, 2023					
	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												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 17	$ —	$ 17	$ —	$ 17
Other derivative instruments:												
Commodity trading	7	35	5	47	(23)	24	6	86	5	97	(60)	37
Electric commodity	—	—	1	1	(1)	—	—	—	7	7	(7)	—
Natural gas commodity	—	7	—	7	—	7	—	12	—	12	—	12
Total current derivative liabilities	$ 7	$ 42	$ 6	$ 55	$ (24)	31	$ 6	$ 115	$ 12	$ 133	$ (67)	66
PPAs [(b)]						6						8
Current derivative instruments						$ 37						$ 74
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 11	$ 32	$ 40	$ 83	$ (22)	$ 61	$ 16	$ 50	$ 37	$ 103	$ (39)	$ 64
Total noncurrent derivative liabilities	$ 11	$ 32	$ 40	$ 83	$ (22)	61	$ 16	$ 50	$ 37	$ 103	$ (39)	64
PPAs [(b)]						16						22
Noncurrent derivative instruments						$ 77						$ 86

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement. At Dec. 31, 2024 and 2023, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2024 and 2023, derivative assets and liabilities include rights to reclaim cash collateral of $2 million and $7 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) Xcel Energy currently applies the normal purchase exception to qualifying PPAs. Balance relates to specific contracts that were previously recognized at fair value prior to applying the normal purchase exception, and are being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	2024	2023	2022
Balance at Jan. 1	$ 90	$ 236	$ 19
Purchases [(a)]	210	176	406
Settlements [(a)]	(303)	(154)	(350)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(b)]	(9)	6	151
Net gains (losses) recognized as regulatory assets and liabilities [(a)]	111	(174)	10
Balance at Dec. 31	$ 99	$ 90	$ 236

(a) Relates primarily to NSP-Minnesota and SPS FTR instruments administered by MISO and SPP, respectively.

(b) Relates to commodity trading and is subject to substantial offsetting losses and gains on derivative instruments categorized as levels 1 and 2 in the income statement. See above tables for the income statement impact of derivative activity, including commodity trading gains and losses.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2024		2023	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 28,419	$ 25,115	$ 25,465	$ 22,927

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 Dec. 31, 2024 and 2023, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits.

The average annual interest crediting rates for these plans was 4.90, 4.72 and 4.89% in 2024, 2023, and 2022, respectively.

Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2024 and 2023 were $13 million and $12 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $2 million in 2024 and $2 million in 2023.

Xcel Energy's postretirement health care benefit plan is a continuation of certain welfare benefit programs for current employees. A full-time employee's date of hire or a retiree's date of retirement determine eligibility for each of the programs.

Xcel Energy's investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as the long-term projected return levels from investment experts.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2024 were below the assumed level of 6.93%.
- Investment returns in 2023 were above the assumed level of 6.93%.
- Investment returns in 2022 were below the assumed level of 6.49%.
- In 2025, expected investment-return assumption is 7.13%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk.

The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit plans for Texas and New Mexico equal to amounts collected in rates. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time.

The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

	Dec. 31, 2024 [(a)]					Dec. 31, 2023 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 117	$ —	$ —	$ —	$ 117	$ 233	$ —	$ —	$ —	$ 233
Commingled funds	—	—	—	1,694	1,694	491	—	—	1,235	1,726
Debt securities	—	656	6	—	662	—	683	4	—	687
Equity securities	25	—	—	—	25	35	—	—	—	35
Other	—	6	—	—	6	—	9	—	—	9
Total	$ 142	$ 662	$ 6	$ 1,694	$ 2,504	$ 759	$ 692	$ 4	$ 1,235	$ 2,690

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2024 [(a)]					Dec. 31, 2023 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 35	$ —	$ —	$ —	$ 35	$ 33	$ —	$ —	$ —	$ 33
Insurance contracts	—	40	—	—	40	—	40	—	—	40
Commingled funds	—	—	—	68	68	22	—	—	72	94
Debt securities	—	201	—	—	201	—	187	1	—	188
Other	—	—	—	—	—	—	1	—	—	1
Total	$ 35	$ 241	$ —	$ 68	$ 344	$ 55	$ 228	$ 1	$ 72	$ 356

(a) See Note 10 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2024 and 2023.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2024	2023	2024	2023
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 2,943	$ 2,871	$ 394	$ 405
Service cost	76	74	1	1
Interest cost	151	158	21	22
Plan amendments	—	(3)	—	—
Actuarial (gain) loss	(77)	126	55	14
Plan participants' contributions	—	—	9	8
Benefit payments [(a)]	(341)	(283)	(53)	(56)
Obligation at Dec. 31	$ 2,752	$ 2,943	$ 427	$ 394
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 2,690	$ 2,685	$ 356	$ 364
Actual return on plan assets	55	238	21	29
Employer contributions	100	50	11	11
Plan participants' contributions	—	—	9	8
Benefit payments	(341)	(283)	(53)	(56)
Fair value of plan assets at Dec. 31	2,504	2,690	344	356
Funded status of plans at Dec. 31	$ (248)	$ (253)	$ (83)	$ (38)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ —	$ 1	$ 10	$ 28
Current liabilities	—	—	(4)	(3)
Noncurrent liabilities	(248)	(254)	(89)	(63)
Net amounts recognized	$ (248)	$ (253)	$ (83)	$ (38)

(a) Includes lump-sum benefit payments used in the determination of settlement charges of $168 million in 2024.

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	2024	2023	2024	2023
Discount rate for year-end valuation	5.88 %	5.49 %	5.88 %	5.54 %
Expected average long-term increase in compensation level	4.25 %	4.25 %	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	7.00 %	6.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	7.50 %	5.50 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	9	6

Accumulated benefit obligation for the pension plan was $2,554 million and $2,728 million as of Dec. 31, 2024 and 2023, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2024	2023	2022	2024	2023	2022
Service cost	$ 76	$ 74	$ 97	$ 1	$ 1	$ 2
Interest cost	151	158	110	21	22	15
Expected return on plan assets	(206)	(209)	(208)	(17)	(17)	(18)
Amortization of prior service credit	(2)	(1)	(1)	—	(1)	(6)
Amortization of net loss	30	22	75	2	1	2
Settlement charge [(a)]	67	—	71	—	—	—
Net periodic pension cost (credit)	116	44	144	7	6	(5)
Effects of regulation	(37)	30	(30)	—	—	3
Net benefit cost (credit) recognized for financial reporting	$ 79	$ 74	$ 114	$ 7	$ 6	$ (2)
Significant Assumptions Used to Measure Costs:						
Discount rate	5.49 %	5.80 %	3.08 %	5.54 %	5.80 %	3.09 %
Expected average long-term increase in compensation level	4.25	4.25	3.75	—	—	—
Expected average long-term rate of return on assets	6.93	6.93	6.49	5.00	5.00	4.10

(a) 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 2024 and 2022, as a result of lump-sum distributions during each plan year, Xcel Energy recorded a total pension settlement charge of $67 million and $71 million, respectively, the majority of which was not recognized due to the effects of regulation. A total of $8 million and $9 million was recorded in the consolidated statements of income in 2024 and 2022, respectively. There were no settlement charges recorded for the qualified pension plans in 2023.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2024	2023	2024	2023
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,074	$ 1,096	$ 113	$ 64
Prior service credit	(8)	(9)	—	—
Total	$ 1,066	$ 1,087	$ 113	$ 64
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 32	$ 20	$ 2	$ 2
Noncurrent regulatory assets	983	1,014	127	79
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(18)	(19)
Deferred income taxes	14	14	1	1
Net-of-tax accumulated other comprehensive income	37	39	2	2
Total	$ 1,066	$ 1,087	$ 113	$ 64
Measurement date	Dec. 31, 2024	Dec. 31, 2023	Dec. 31, 2024	Dec. 31, 2023

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2022 - 2025 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $125 million in January 2025.
- $100 million in 2024.
- $50 million in 2023.
- $50 million in 2022.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- $8 million expected during 2025.
- $11 million during 2024.
- $11 million during 2023.
- $13 million during 2022.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2024	2023	2024	2023
Long-duration fixed income securities	38 %	38 %	— %	— %
Domestic and international equity securities	31	31	25	9
Alternative investments	20	20	11	13
Short-to-intermediate fixed income securities	9	9	61	77
Cash	2	2	3	1
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year.

Plan Amendments — There were no significant plan amendments made in 2024 and 2022 which affected the pension or postretirement benefit obligation.

In 2023, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental social security benefits for all active participants on and after Jan. 1, 2024.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2025	$ 235	$ 44	$ 3	$ 41
2026	226	43	3	40
2027	229	42	3	39
2028	231	42	3	39
2029	237	40	3	37
2030-2034	1,137	187	18	169

Voluntary Retirement Program

Incremental to amounts presented above for postretirement benefits, Xcel Energy has postemployment costs and obligations for its Voluntary Retirement Program, under which approximately 400 eligible non-bargaining employees retired in the fourth quarter of 2023.

Utilizing employee information and the following inputs, unfunded obligations of $29 million and $34 million for health plan subsidies and $4 million and $5 million for other medical benefits are presented in other current liabilities and noncurrent pension and employee benefit obligations in the consolidated balance sheets as of Dec. 31, 2024 and 2023, respectively.

Significant Assumptions to Measure Benefit Obligations:	2024	2023
Discount rate for year-end valuation	5.00 %	5.50 %
Mortality table	PRI-2012	PRI-2012
Health care costs trend rate	7.00 %	7.00 %
Ultimate trend assumption	4.50 %	N/A
Years until ultimate trend is reached	9	N/A

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $50 million in 2024, $49 million in 2023 and $46 million in 2022.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans.

Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer pension plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

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 a multi-district litigation matter consisting of a Wisconsin purported class (Arandell Corp.). The Court issued a ruling in June 2022 granting plaintiffs' class certification. In April 2023, the Seventh Circuit Court of Appeals heard the defendants' appeal challenging whether the district court properly assessed class certification. A decision relating to class certification is forthcoming. Xcel Energy considers the reasonably possible loss associated with this litigation to be immaterial.

***Comanche Unit 3 Litigation* —** In 2021, CORE filed a lawsuit in Denver County District Court, alleging PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. In April 2022, CORE filed a supplement to include damages related to a 2022 outage. Also in 2022, CORE sent notice of withdrawal from the ownership agreement based on the same alleged breaches.

In October 2023, the jury ruled that CORE may not withdraw as a joint owner of the facility but awarded CORE lost power damages of $26 million. PSCo recognized $35 million of losses for the verdict in 2023, including estimated interest and other costs. In the fourth quarter of 2024, PSCo and CORE reached a settlement, PSCo paid CORE the agreed to amounts and all appeals and related actions have been dismissed.

Marshall Wildfire Litigation — In December 2021, a wildfire ignited in Boulder County, Colorado (Marshall Fire), which burned over 6,000 acres and destroyed or damaged over 1,000 structures. On June 8, 2023, the Boulder County Sheriff's Office released its Marshall Fire Investigative Summary and Review and its supporting documents (Sheriff's Report). According to an October 2022 statement from the Colorado Insurance Commissioner, the Marshall Fire is estimated to have caused more than $2 billion in property losses.

According to the Sheriff's Report, on Dec. 30, 2021, a fire ignited on a residential property in Boulder, Colorado, located in PSCo's service territory, for reasons unrelated to PSCo's power lines. According to the Sheriff's Report, approximately one hour and 20 minutes after the first ignition, a second fire ignited just south of the Marshall Mesa Trailhead in unincorporated Boulder County, Colorado, also located in PSCo's service territory. According to the Sheriff's Report, the second ignition started approximately 80 to 110 feet away from PSCo's power lines in the area.

The Sheriff's Report states that the most probable cause of the second ignition was hot particles discharged from PSCo's power lines after one of the power lines detached from its insulator in strong winds, and further states that it cannot be ruled out that the second ignition was caused by an underground coal fire. According to the Sheriff's Report, no design, installation or maintenance defects or deficiencies were identified on PSCo's electrical circuit in the area of the second ignition. PSCo disputes that its power lines caused the second ignition.

PSCo is aware of 307 complaints, most of which have also named Xcel Energy Inc. and Xcel Energy Services Inc. as additional defendants, relating to the Marshall Fire. The complaints are on behalf of at least 4,087 plaintiffs. The complaints generally allege that PSCo's equipment ignited the Marshall Fire and assert various causes of action under Colorado law, including negligence, premises liability, trespass, nuisance, wrongful death, willful and wanton conduct, negligent infliction of emotional distress, loss of consortium and inverse condemnation. In addition to seeking compensatory damages, certain of the complaints also seek exemplary damages.

In September 2023, the Boulder County District Court Judge consolidated the pending lawsuits into a single action for pretrial purposes and has subsequently consolidated additional lawsuits that have been filed. At the case management conference in February 2024, a trial date was set for September 2025. Discovery is now underway.

In September 2024, the Judge presiding over the consolidated cases in Boulder County issued an order regarding the trial that resolves, on a preliminary basis, certain disputes over the structure of the September 2025 trial. The Court ruled that all Plaintiffs should be bound by a trial on liability unless they opt-out with good cause. The Court also ruled that liability and damages should be largely or entirely tried separately, meaning that common questions of law and fact regarding liability would be decided first, and a majority or all of the damages phase will occur separately following the liability phase of trial. The individual plaintiffs filed a motion for reconsideration of the opt-out portion of this order, which the Court denied in November 2024, confirming that plaintiffs will have to demonstrate good cause in order to opt out of the trial. The Court also denied PSCo's request for a change in venue, ruling that the trial will take place in Boulder County.

Colorado courts do not apply strict liability in determining an electric utility company's liability for fire-related damages. For inverse condemnation claims, Colorado courts assess whether a defendant acted with intent to take a plaintiff's property or intentionally took an action which has the natural consequence of taking the property. For negligence claims, Colorado courts look to whether electric power companies have operated their system with a heightened duty of care consistent with the practical conduct of its business, and liability does not extend to occurrences that cannot be reasonably anticipated.

Colorado law does not impose joint and several liability in tort actions. Instead, under Colorado law, a defendant is liable for the degree or percentage of the negligence or fault attributable to that defendant, except where the defendant conspired with another defendant. A jury's verdict in a Colorado civil case must be unanimous. Under Colorado law, in a civil action filed before Jan. 1, 2025, other than a medical malpractice action, the total award for noneconomic loss is capped at $0.6 million per defendant unless the court finds justification to exceed that amount by clear and convincing evidence, in which case the maximum doubles.

Colorado law caps punitive or exemplary damages to an amount equal to the amount of the actual damages awarded to the injured party, except the court may increase any award of punitive damages to a sum up to three times the amount of actual damages if the conduct that is the subject of the claim has continued during the pendency of the case or the defendant has acted in a willful and wanton manner during the action which further aggravated plaintiff's damages.

In the event Xcel Energy Inc. or PSCo was found liable related to this litigation and were required to pay damages, such amounts could exceed our insurance coverage of approximately $500 million and have a material adverse effect on our financial condition, results of operations or cash flows. However, due to uncertainty as to the cause of the fire and the extent and magnitude of potential damages, Xcel Energy Inc. and PSCo are unable to estimate the amount or range of possible losses in connection with the Marshall Fire.

2024 Smokehouse Creek Fire Complex — On February 26, 2024, multiple wildfires began in the Texas Panhandle, including the Smokehouse Creek Fire and the 687 Reamer Fire, which burned into the perimeter of the Smokehouse Creek Fire (together, referred to herein as the "Smokehouse Creek Fire Complex"). The Texas A&M Forest Service issued incident reports that determined that the Smokehouse Creek Fire and the 687 Reamer Fire were caused by power lines owned by SPS after wooden poles near each fire origin failed. According to the Texas A&M Forest Service's Incident Viewer and news reports, the Smokehouse Creek Fire Complex burned approximately 1,055,000 acres.

SPS is aware of approximately 25 complaints, most of which have also named Xcel Energy Services Inc. as an additional defendant, relating to the Smokehouse Creek Fire Complex. The complaints generally allege that SPS' equipment ignited the Smokehouse Creek Fire Complex and seek compensation for losses resulting from the fire, asserting various causes of action under Texas law. In addition to seeking compensatory damages, certain of the complaints also seek exemplary damages. SPS has also received approximately 205 claims for losses related to the Smokehouse Creek Fire Complex through its claims process and has reached final settlements on 129 of those claims as of the date of this filing. In addition to filed complaints and claims made through SPS' claims process, SPS has also received information from attorneys for claims related to the Smokehouse Creek Fire Complex which have not been submitted through the claims process and have also not been filed as lawsuits, and has reached settlement of a portion of those claims. SPS anticipates additional complaints and demands will be made. As of December 2024, SPS has settled claims related to both of the fatalities believed to be associated with the Smokehouse Creek Fire Complex.

Texas law does not apply strict liability in determining an electric utility company's liability for fire-related damages. For negligence claims under Texas law, a public utility has a duty to exercise ordinary and reasonable care.

Potential liabilities related to the Smokehouse Creek Fire Complex depend on various factors, including the cause of the equipment failure and the extent and magnitude of potential damages, including damages to residential and commercial structures, personal property, vegetation, livestock and livestock feed (including replacement feed), personal injuries and any other damages, penalties, fines or restitution that may be imposed by courts or other governmental entities if SPS is found to have been negligent.

Based on the current state of the law and the facts and circumstances available as of the date of this filing, Xcel Energy believes it is probable that it will incur a loss in connection with the Smokehouse Creek Fire Complex and accordingly has recorded a total of $215 million of estimated losses for the matter (before available insurance). Settlements reached as of the date of this filing total $76 million of expected loss payments, of which $35 million were paid in 2024, resulting in a remaining estimated liability of $180 million presented in other current liabilities as of Dec. 31, 2024.

The cumulative estimated probable losses of $215 million for complaints and claims in connection with the Smokehouse Creek Fire Complex (before available insurance) corresponds to the lower end of the range of Xcel Energy's reasonably estimable range of losses, and is subject to change based on additional information. This $215 million estimate does not include, among other things, amounts for (i) potential penalties or fines that may be imposed by governmental entities on Xcel Energy, (ii) exemplary or punitive damages, (iii) compensation claims by federal, state, county and local government entities or agencies, (iv) compensation claims for damage to trees, railroad lines, or oil and gas equipment, or (v) other amounts that are not reasonably estimable.

Xcel Energy remains unable to reasonably estimate any additional loss or the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability. In the event that SPS or Xcel Energy Services Inc. was found liable related to the litigation related to the Smokehouse Creek Fire Complex and was required to pay damages, such amounts could exceed our insurance coverage of approximately $500 million for the annual policy period and could have a material adverse effect on our financial condition, results of operations or cash flows.

The process for estimating losses associated with potential claims related to the Smokehouse Creek Fire Complex requires management to exercise significant judgment based on a number of assumptions and subjective factors, including the factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the potential financial impact of the Smokehouse Creek Fire Complex may change.

SPS records insurance recoveries when it is deemed probable that recovery will occur, and SPS can reasonably estimate the amount or range. SPS has recorded an insurance receivable, net of recoveries received, for $210 million, presented within prepayments and other current assets as of Dec. 31, 2024. While SPS plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries.

Rate Matters and Other

Xcel Energy's operating subsidiaries are involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the consolidated financial statements.

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. 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 July 2022, the MPUC referred the matter to the Office of Administrative Hearings to conduct a contested case on the prudence of the replacement power costs incurred by NSP-Minnesota.

In May 2024, the ALJ recommended a customer refund of $34 million (less a portion of the proceeds received from the settlement with GE). The ALJ indicated that consideration of the $22 million of previously disallowed costs was not in the scope of their recommendation. In 2024, following contested case procedures, Xcel recognized a customer refund of $47 million for replacement power incurred during the outage.

Minnesota 2023 Fuel Clause Adjustment — In March 2024, NSP-Minnesota filed its annual FCA true-up petition to the MPUC.

In 2024, the DOC recommended customer refunds for 2023 replacement power costs incurred during an outage at the Prairie Island generating station (October 2023 through February 2024). NSP-Minnesota estimates that customer refunds would be approximately $22 million if the DOC recommendations are applied to both 2023 and 2024.

In September 2024, the MPUC ruled NSP-Minnesota was imprudent in the operation of the Prairie Island nuclear plant based on an incident that resulted in the extended outage. The MPUC did not quantify the refund and referred the determination of the refund amount to the Office of Administrative Hearings. NSP-Minnesota has recorded an estimated liability for a customer refund. The procedural schedule is as follows:

- Xcel Energy testimony: May 1, 2025
- Intervenor direct testimony: July 2, 2025
- Rebuttal testimony: August 13, 2025
- ALJ Report: March 16, 2026

Cabin Creek Prudency Review — In 2015, the CPUC granted a CPCN for an $88 million upgrade project to increase the generating and storage capacity of the Cabin Creek hydroelectric storage facility, which anticipated project completion in 2020. Due to significant and unforeseen challenges, the project was not completed until 2023 and cost approximately $110 million. In July 2024, PSCo filed direct testimony in a prudency review for the upgrade project, outlining the project's timelines, costs, benefits and challenges.

In February 2025, PSCo received answer testimony from CPUC Staff and UCA including proposed disallowances, primarily for replacement power and lost capacity. CPUC Staff recommended a disallowance of $21 million and UCA's testimony included recommendations for total disallowances ranging from $71 million to $138 million. PSCo will file its rebuttal testimony in March 2025, responding to answer testimony and continuing to assert that its actions related to the project were prudent, and that therefore no disallowance should be granted.

The remainder of the procedural schedule includes:

- Settlement testimony: April 4, 2025
- Hearing: April 17-18, 2025
- Statements of position: May 9, 2025

A final CPUC decision is expected in the second half of 2025.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

MGP, Landfill and Disposal Sites

Xcel Energy is investigating, remediating or performing post-closure actions at 13 historical MGP, landfill or other disposal sites across its service territories, excluding sites that are being addressed under current coal ash regulations (see below).

Xcel Energy has approximately $20 million of remaining liabilities for resolution of these issues, however, the final outcome and timing are unknown. In addition, there may be regulatory recovery, 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 is subject to the CCR Rule, which imposes requirements for handling, storage, treatment and disposal of coal ash and other solid waste.

In May 2024, final amendments to the CCR Rule were published, widening its scope to include legacy CCR surface impoundments at inactive facilities and previously exempt areas where CCR was placed directly on land at CCR-regulated facilities, including areas of beneficial use.

As a requirement of the CCR Rule, utilities must complete facility evaluations and groundwater sampling around their subject landfills, surface impoundments and certain other areas where coal ash was placed on land.

If certain impacts to groundwater are detected, utilities are required to perform additional groundwater investigations and/or perform corrective actions beginning with an Assessment of Corrective Measures.

Investigation and/or corrective action related to groundwater impacts are currently underway at certain active and closed coal-generating facilities at a current estimated cost of at least $45 million. In addition, Xcel Energy expects to incur $15 million for investigations through 2028 to perform required reporting and assess whether corrective actions are necessary. AROs have been recorded for each of these activities, and amounts are expected to be recoverable through regulatory mechanisms.

Xcel Energy has also identified coal ash that is expected to be required to be removed from certain closed coal-fueled generating facilities at estimated costs totaling approximately $100 million. AROs have been recorded, with the costs expected to be recoverable through regulatory mechanisms.

Xcel Energy continues to evaluate the 2024 updates to the CCR Rule, the interpretations of those updates and how they will apply to specific sites. Assessment of the recent updates to the CCR Rule and corresponding site investigation activities may result in updates to estimated costs as well as identification of additional required corrective actions.

Clean Water Act Section 316(b) — The Federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure they reflect the best technology available for minimizing impingement and entrainment of aquatic species.

Estimated capital expenditures of approximately $50 million may be required to comply with the requirements. Xcel Energy anticipates these costs will be recoverable through regulatory mechanisms.

Environmental Requirements — Air

Clean Air Act NOx Allowance Allocations — In June 2023, the EPA published final regulations for ozone under the "Good Neighbor" provisions of the Clean Air Act. The final rule applies to generation facilities in Minnesota, Texas and Wisconsin, as well as other states outside of our service territory. In February 2024, the EPA proposed to include New Mexico in the rule. The rule establishes an allowance trading program for NOx that will impact Xcel Energy fossil fuel-fired electric generating facilities. Subject facilities will have to secure additional allowances, install NOx controls and/or develop a strategy of operations that utilizes the existing allowance allocations.

While the financial impacts of the final rule are uncertain and dependent on market forces and anticipated generation, Xcel Energy anticipates the annual costs could be significant, but would be recoverable through regulatory mechanisms.

In June 2024, the U.S. Supreme Court issued an order granting a stay of the final rule. In response, the EPA issued a nationwide administrative stay of the rule. Depending on the outcomes of the underlying legal challenges, the regulation may become applicable in the future.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning was $3.5 billion and $3.2 billion for 2024 and 2023, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2024	Amounts Incurred (a)	Amounts Settled	Accretion	Cash Flow Revisions (b)	Dec. 31, 2024
Electric						
Nuclear	$ 2,107	$ —	$ —	$ 106	$ 263	$ 2,476
Wind	526	—	—	19	(36)	509
Steam, hydro and other production	361	109	(6)	18	13	495
Distribution	49	—	—	2	—	51
Natural gas						
Transmission and distribution	172	—	—	8	(1)	179
Other						
Miscellaneous	3	—	—	—	—	3
Total liability	$ 3,218	$ 109	$ (6)	$ 153	$ 239	$ 3,713

(a) Amounts incurred largely pertain to CCR coal ash regulations and new obligations associated with Sherco Solar Unit 1 , which was placed in service in 2024.

(b) In 2024, AROs were revised for changes in timing and estimates of cash flows. Changes were driven by updated assumptions in the NSP-Minnesota nuclear decommissioning triennial filing coupled with discount rate and escalation rate changes. Wind, steam, hydro and other production AROs were revised due to the results of the 2024 dismantling studies and changes in cost estimates to remediate ash containment facilities.

(Millions of Dollars)	Jan. 1, 2023	Amounts Incurred (a)	Amounts Settled	Accretion	Cash Flow Revisions (b)	Dec. 31, 2023
Electric						
Nuclear	$ 2,160	$ —	$ —	$ 105	$ (158)	$ 2,107
Wind	514	10	—	19	(17)	526
Steam, hydro and other production	348	—	(1)	15	(1)	361
Distribution	48	—	—	1	—	49
Natural gas						
Transmission and distribution	307	—	—	14	(149)	172
Other						
Miscellaneous	3	—	—	—	—	3
Total liability	$ 3,380	$ 10	$ (1)	$ 154	$ (325)	$ 3,218

(a) Amounts incurred relate to the Northern Wind farm placed in service in NSP-Minnesota.

(b) In 2023, AROs were revised for changes in timing and estimates of cash flows. Revisions in wind and nuclear AROs were primarily incurred due to changes in useful lives. Changes in gas transmission and distribution AROs were a result of updated gas line mileage and number of services, as well as changes to inflation and discount rate assumptions.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2024. Therefore, an ARO was not recorded for these facilities.

Nuclear

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $16.3 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has $500 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $15.8 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $166 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $25 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI for each of NSP-Minnesota's two nuclear plant sites. The coverage limits are $2.8 billion for both Monticello and Prairie Island. NEIL also provides business interruption insurance coverage up to $490 million and $420 million at Monticello and Prairie Island, respectively, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of $19 million for business interruption insurance and $34 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life. In October 2023, a CON for additional storage at the Monticello site was approved by the MPUC to support extended operations to 2040.

The Prairie Island dry-cask storage facility currently stores 52 of the 64 authorized casks. In February 2024, NSP-Minnesota filed a CON with the MPUC for additional storage at Prairie Island to support possible life extension to 2054.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's authorized retirement dates, which can be different than the currently approved NRC operating licenses. These decommissioning activities are planned to be completed at both facilities by 2101.

NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2050 and its Prairie Island nuclear plant until 2033 for Unit 1 and 2034 for Unit 2. NSP-Minnesota's authorized retirement dates are 2040 for Monticello, 2033 for PI Unit 1 and 2034 for PI Unit 2. In February 2025, the MPUC approved a settlement agreement which extends the retirement dates for planning purposes to 2050, 2053, and 2054 for Monticello, PI Unit 1, and PI Unit 2, respectively. Requests to update the authorized retirement dates are expected to be submitted to the MPUC in 2025.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The most recent triennial decommissioning study was filed in December 2024.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had $3.5 billion and $3.2 billion of assets held in external decommissioning trusts at Dec. 31, 2024 and 2023, respectively.

See Note 10 to the consolidated financial statements for additional discussion.

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. A contract determined to contain a lease is evaluated further to determine whether the arrangement is an operating lease or a finance lease.

ROU assets represent Xcel Energy's rights to use leased assets. The present value of future operating lease payments is recognized in other current operating lease liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted average of 4.6%). For currently existing asset classes, Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
PPAs	$ 1,802	$ 1,832
Other	373	315
Gross operating lease ROU assets	2,175	2,147
Accumulated amortization	(1,115)	(930)
Net operating lease ROU assets	$ 1,060	$ 1,217

ROU assets for finance leases are included in other noncurrent assets, and the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities.

Xcel Energy's most significant finance lease activities are related to WYCO, a joint venture with CIG, to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service and Front Range pipeline arrangements with CIG and WYCO, respectively, as finance leases. Xcel Energy Inc. eliminates 50% of the finance lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
Gas storage facilities	$ 160	$ 160
Gas pipeline	21	21
Gross finance lease ROU assets	181	181
Accumulated amortization	(70)	(67)
Net finance lease ROU assets	$ 111	$ 114

Components of lease expense:

(Millions of Dollars)	2024	2023	2022
Operating leases			
PPA capacity payments	$ 228	$ 241	$ 241
Other operating leases [(a)]	43	42	39
Total operating lease expense [(b)]	$ 271	$ 283	$ 280
Finance leases			
Amortization of ROU assets	$ 3	$ 3	$ 4
Interest expense on lease liability	15	15	16
Total finance lease expense	$ 18	$ 18	$ 20

(a) Includes short-term lease expense of $4 million, $3 million, and $6 million for 2024, 2023 and 2022, 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 Dec. 31, 2024:

(Millions of Dollars)	PPA [a] [b] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [c]
2025	$ 240	$ 31	$ 271	$ 10
2026	210	33	243	9
2027	162	27	189	8
2028	107	27	134	8
2029	59	22	81	8
Thereafter	199	238	437	165
Total minimum obligation	977	378	1,355	208
Interest component of obligation	(115)	(146)	(261)	(146)
Present value of minimum obligation	$ 862	232	1,094	62
Less current portion			(227)	(2)
Noncurrent operating and finance lease liabilities			$ 867	$ 60
Weighted-average remaining lease term in years			8.7	35.8

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.
(b) PPA operating leases contractually expire at various dates through 2039.
(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered, and may also include capacity payments. Certain non-lease PPAs with various expiration dates through 2041, contain minimum energy purchase commitments. Total energy payments on those contracts were $212 million, $214 million and $182 million in 2024, 2023 and 2022, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $81 million, $77 million and $75 million in 2024, 2023 and 2022, respectively.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2024, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these non-lease contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2025	$ 51	$ 111
2026	34	64
2027	14	21
2028	6	22
2029	6	22
Thereafter	2	—
Total	$ 113	$ 240

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2025 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities delivered under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2024:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2025	$ 337	$ 168	$ 420	$ 345
2026	130	62	11	350
2027	76	133	—	312
2028	1	19	—	185
2029	1	67	—	103
Thereafter	1	49	—	632
Total	$ 546	$ 498	$ 431	$ 1,927

VIEs

PPAs — 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. Xcel Energy has determined that certain IPPs are VIEs, however Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because Xcel Energy does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 3,751 MW of capacity under long-term PPAs as of both Dec. 31, 2024 and 2023, with entities that have been determined to be VIEs. These agreements have expiration dates through 2048.

Fuel Contracts — SPS purchases all of its coal requirements for its Tolk plant from TUCO Inc. under contracts that will expire in December 2027. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships with affordable rental housing activities that qualify for low-income housing tax credits.

Eloigne and NSP-Wisconsin, as primary beneficiaries of these activities, consolidate these limited partnerships in their consolidated financial statements.

Amounts reflected in Xcel Energy's consolidated balance sheets for these investments include $40 million of assets and $34 million of liabilities at Dec. 31, 2024, and $41 million of assets and $35 million of liabilities at Dec. 31, 2023.

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 specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum amount.

As of Dec. 31, 2024 and 2023, 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 $93 million and $75 million at Dec. 31, 2024 and 2023, 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 terms of duration and amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

13. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

	2024		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (53)	$ (41)	$ (94)
Other comprehensive income (loss) before reclassifications	22	(3)	19
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	2 [(a)]	—	2
Amortization of net actuarial loss	—	5 [(b)]	5
Net current period other comprehensive income	24	2	26
Accumulated other comprehensive loss at Dec. 31	$ (29)	$ (39)	$ (68)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

	2023		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (54)	$ (39)	$ (93)
Other comprehensive loss before reclassifications	(2)	(4)	(6)
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	3 [(a)]	—	3
Amortization of net actuarial loss	—	2 [(b)]	2
Net current period other comprehensive income (loss)	1	(2)	(1)
Accumulated other comprehensive loss at Dec. 31	$ (53)	$ (41)	$ (94)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segment Information

Xcel Energy's chief operating decision maker, the CEO, sets financial performance objectives and budgets and establishes separate targets for the regulated electric utility net income of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility net income of NSP-Minnesota, NSP-Wisconsin and PSCo.

The regulated electric utility and regulated natural gas utility segments are managed separately because of inherent differences between activities to serve electric customers and those required to serve natural gas customers, and as the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment. The CEO assesses financial performance, including quarterly and annual budget-to-actual and year-over-year variances in revenues and expenses, to inform operating decisions, capital investments and cost recovery strategies.

Xcel Energy has the following reportable segments:

- **Regulated Electric Utility** — The regulated electric utility segment generates, purchases, transmits, distributes and sells electricity in Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin; each state's regulated electric utility activities qualify as an operating segment, and is aggregated into Xcel Energy's regulated electric utility segment. 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 Utility** — The regulated natural gas utility segment purchases, transports, stores, distributes and sells natural gas primarily in portions of Colorado, Michigan, Minnesota, North Dakota and Wisconsin; each state's regulated natural gas utility activities qualify as an operating segment, and is aggregated into Xcel Energy's regulated natural gas utility segment.

Equity method investments in the regulated natural gas utility segment of $85 million and $92 million at Dec. 31, 2024 and 2023, respectively, primarily relate to WYCO. Non-segment equity method investments of $161 million and $152 million as of Dec. 31, 2024 and 2023, respectively, relate to investments in energy technology funds.

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.

Other segment expenses, net, for the reportable segments includes conservation and DSM expenses, taxes (other than income taxes), other income (expense), net, earnings from equity method investments, intersegment expenses and AFUDC - equity.

Non-segment revenues include steam, appliance repair and non-utility real estate activities and revenues associated with processing solid waste into RDF and from investments in rental housing projects that qualify for low-income housing tax credits. Non-segment net loss also includes costs associated with these activities as well as unallocated corporate O&M expenses, interest charges and income taxes as well as earnings from equity method investments in energy technology funds.

Segment information and reconciliations to Xcel Energy's consolidated operating revenues and net income:

	2024		
(Millions of Dollars)	**Regulated electric utility**	**Regulated natural gas utility**	**Total segments**
Operating revenues	$ 11,147	$ 2,230	$ 13,377
Intersegment revenue	2	22	24
Total segment revenues	11,149	2,252	13,401
Electric fuel and purchased power	3,788	—	3,788
Cost of natural gas sold and transported	—	951	951
O&M expenses	2,102	409	2,511
Depreciation and amortization	2,373	357	2,730
Other segment expenses, net	693	123	816
Interest charges and financing costs	767	113	880
Income tax (benefit) expense	(420)	62	(358)
Net income	$ 1,846	$ 237	$ 2,083

Total segment revenues	$ 13,401
Eliminate intersegment revenue	(24)
Non-segment revenues	64
Consolidated operating revenues	$ 13,441
Total segment net income	$ 2,083
Non-segment net loss	(147)
Consolidated net income	$ 1,936

	2023		
(Millions of Dollars)	**Regulated electric utility**	**Regulated natural gas utility**	**Total segments**
Operating revenues	$ 11,446	$ 2,645	$ 14,091
Intersegment revenue	2	3	5
Total segment revenues	11,448	2,648	14,096
Electric fuel and purchased power	4,278	—	4,278
Cost of natural gas sold and transported	—	1,456	1,456
O&M expenses	2,011	386	2,397
Depreciation and amortization	2,111	323	2,434
Other segment expenses, net [(a)]	827	118	945
Interest charges and financing costs	670	96	766
Income tax (benefit) expense	(135)	50	(85)
Net income	$ 1,686	$ 219	$ 1,905

Total segment revenues	$ 14,096
Eliminate intersegment revenue	(5)
Non-segment revenues	115
Consolidated operating revenues	$ 14,206
Total segment net income	$ 1,905
Non-segment net loss	(134)
Consolidated net income	$ 1,771

(a) Other segment expenses, net, for 2023 additionally includes loss on Comanche Unit 3 litigation and workforce reduction expenses.

	2022		
(Millions of Dollars)	**Regulated electric utility**	**Regulated natural gas utility**	**Total segments**
Operating revenues	$ 12,123	$ 3,080	$ 15,203
Intersegment revenue	2	2	4
Total segment revenues	12,125	3,082	15,207
Electric fuel and purchased power	5,005	—	5,005
Cost of natural gas sold and transported	—	1,910	1,910
O&M expenses	2,069	370	2,439
Depreciation and amortization	2,122	276	2,398
Other segment expenses, net	824	108	932
Interest charges and financing costs	636	86	722
Income tax (benefit) expense	(162)	68	(94)
Net income	$ 1,631	$ 264	$ 1,895

Total segment revenues	$ 15,207
Eliminate intersegment revenue	(4)
Non-segment revenues	107
Consolidated operating revenues	$ 15,310
Total segment net income	$ 1,895
Non-segment net loss	(159)
Consolidated net income	$ 1,736

15. Workforce Reduction

In 2023, Xcel Energy implemented workforce actions to align resources and investments with evolving business and customer needs, and streamline the organization for long-term success.

In September 2023, Xcel Energy announced a voluntary retirement program to a group of eligible non-bargaining employees, with an enhanced retirement package including certain health care and cash benefits for accepted employees. Approximately 400 employees retired under this program in December 2023.

In November 2023, Xcel Energy, Inc. also reduced its non-bargaining workforce by approximately 150 employees through an involuntary severance program.

In the fourth quarter of 2023, Xcel Energy recorded total expense of $72 million related to these workforce actions, primarily related to the estimated cost of future health plan subsidies and other medical benefits for the voluntary retirement program, as well as severance and other employee payouts and legal and other professional fees.

No such activities occurred in 2024.

For further information on the estimated costs and obligations for future health plan subsidies and other medical benefits, see Note 11 to the consolidated financial statements.

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — 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 Dec. 31, 2024, 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 ended Dec. 31, 2024 that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2024 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in Xcel Energy's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

ITEM 9B — OTHER INFORMATION

None of the Company's directors or officers adopted, modified, or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement during the Company's fiscal quarter ended Dec. 31, 2024.

The company and CEO entered into an aircraft time sharing agreement allowing the CEO to reimburse the company for costs associated with non-business use of company aircraft. A copy of the agreement is filed as Exhibit 10.30 hereto. Xcel Energy encourages non-business use of the company aircraft by the CEO when that use does not interfere with the use of company aircraft for business purposes and provides non-reimbursable access to the CEO for up to 100 hours per annum. Among other advantages, non-business use of the aircraft provides efficiencies, a confidential work environment and enhanced security.

ITEM 9C — DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this Item with respect to Directors and Corporate Governance will be set forth in Xcel Energy Inc.'s Proxy Statement for its 2025 Annual Meeting of Shareholders, which is expected to be filed on April 8, 2025, incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

ITEM 11 — EXECUTIVE COMPENSATION

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2025 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2025 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2025 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item (aggregate fees billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34)) is contained in Xcel Energy Inc.'s Proxy Statement for its 2025 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1	Consolidated Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2024.
	Report of Independent Registered Public Accounting Firm — Financial Statements and Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For each of the three years ended Dec. 31, 2024, 2023 and 2022.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2024, 2023 and 2022.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2024, 2023 and 2022.
	Consolidated Balance Sheets — As of Dec. 31, 2024 and 2023.
	Consolidated Statements of Common Stockholders' Equity — For each of the three years ended Dec. 31, 2024, 2023 and 2022.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2024, 2023 and 2022.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc. Form 8-K dated May 16, 2012	3.01
3.02*	Bylaws of Xcel Energy Inc., as Amended and Restated on August 23, 2023	Xcel Energy Inc. Form 8-K dated August 23, 2023	3.02
4.01*	Description of Securities	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	4.01
4.02*	Indenture, dated as of Dec. 1, 2000, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	4.01
4.03*	Supplemental Indenture No. 3, dated as of June 1, 2006, by and between Xcel Energy Inc. and U.S. Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $300 million of 6.50% Senior Notes, Series due July 1, 2036	Xcel Energy Inc. Form 8-K dated June 6, 2006	4.01
4.04*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $250 million of 4.80% Senior Notes, Series due Sept. 15, 2041	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	4.01
4.05*	Supplemental Indenture No. 8, dated as of June 1, 2015, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $250 million aggregate principal amount of 3.30% Senior Notes, Series due June 1, 2025	Xcel Energy Inc. Form 8-K dated June 1, 2015	4.01
4.06*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $500 million aggregate principal amount of 3.35% Senior Notes, Series due Dec. 1, 2026	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	4.01
4.07*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $500 million aggregate principal amount of 4.00% Senior Notes, Series due June 15, 2028	Xcel Energy Inc. Form 8-K dated June 25, 2018	4.01
4.08*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $500 million aggregate principal amount of 2.60% Senior Notes, Series due Dec 1. 2029 and $500 million aggregate principal amount of 3.50% Senior Notes, Series due Dec. 1, 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	4.01
4.09*	Supplemental Indenture No. 13, dated as of April 1, 2020 by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $600 million aggregate principal amount of 3.40% Senior Notes, Series due June 1, 2030	Xcel Energy Inc. Form 8-K dated April 1, 2020	4.01
4.10*	Supplemental Indenture No. 15, dated as of Nov. 3, 2021 between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $500 million aggregate principal amount of 1.75% Senior Notes, Series due March 15, 2027 and $300 million aggregate principal amount of 2.35% Senior Notes, Series due Nov. 15, 2031	Xcel Energy Inc. Form 8-K dated Nov. 3, 2021	4.01
4.11*	Supplemental Indenture No. 16, dated as of May 6, 2022, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $700 million aggregate principal amount of 4.60% Senior Notes, Series due June 1, 2032	Xcel Energy Form 8-K dated May 6, 2022	4.01
4.12*	Supplemental Indenture No. 17, dated as of August 3, 2023, by and between Xcel Energy Inc. and U.S Bank Trust Company (as successor to Computershare Trust Company, N.A.), as Trustee, creating $800 million aggregate principal amount of 5.45% Senior Notes, Series due August 15, 2033.	Xcel Energy Form 8-K dated August 3, 2023	4.01

4.13*	Supplemental Indenture No. 18, dated as of February 29, 2024 by and between Xcel Energy Inc. and U.S. Bank Trust Company, National Association (as successor to Computershare Trust Company, N.A.), as trustee, creating $800,000,000 aggregate principal amount of 5.50% Senior Notes, Series due March 15, 2034.	Xcel Energy Inc Form 8-K dated February 29, 2024	4.01
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.05
10.03*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.18
10.04*+	Fifth Amendment to Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	10.01
10.05*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	10.01
10.06*+	Eighth Amendment to Exhibit 10.02 dated March 31, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2020	10.02
10.07*+	Ninth Amendment to Exhibit 10.02 dated May 22, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2020	10.01
10.08+	Tenth Amendment to Exhibit 10.02 dated May 20, 2024		
10.09*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.17
10.10*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.07
10.11*+	First Amendment to Exhibit 10.10 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.17
10.12*+	Second Amendment to Exhibit 10.10 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	10.22
10.13*+	Third Amendment to Exhibit 10.10 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	10.01
10.14*+	Fourth Amendment to Exhibit 10.10 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	10.1
10.15*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.34
10.16*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. 2015 Omnibus Incentive Plan for awards between 2020-2023	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	10.32
10.17*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. 2015 Omnibus Incentive Plan for awards in 2024	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2023	10.16
10.18*+	Form of Award Agreement for Retention-Based Restricted Stock Units under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated Dec. 10, 2021	10.01
10.19*+	Xcel Energy Inc. Annual Incentive Plan, effective Feb. 21, 2024	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2023	10.18
10.20*+	Summary of Non-Employee Director Compensation, effective as of May 24, 2023	Xcel Energy Inc. Form 8-K dated Jan. 20, 2025	10.01
10.21*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	Appendix A
10.22*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.23*+	Xcel Energy Inc. 2024 Equity Incentive Plan	Xcel Energy Inc. Form S-8 dated May 22, 2024	4.03
10.24*+	Xcel Energy Inc. Stock Program for Non-Employee Directors (Effective May 22, 2024) under the 2024 Equity Incentive Plan	Xcel Energy Inc. Form 8-K dated May 22, 2024	10.01
10.25+	Form of Award Agreement for Restricted Stock Units under the Xcel Energy Inc. 2024 Equity Incentive Plan for awards since 2025.		
10.26+	Form of Award Agreement for Performance Stock Units under the Xcel Energy Inc. 2024 Equity Incentive Plan for awards since 2025.		
10.27*+	Form of Award Agreement for Retention-Based Restricted Stock Units under the Xcel Energy Inc. 2024 Equity Incentive Plan	Xcel Energy Inc. Form 8-K dated May 22, 2024	10.03
10.28*+	Form of Award Agreement for Restricted Stock under the Xcel Energy Inc. Equity Incentive Plan	Xcel Energy Inc. Form 8-K dated May 22, 2024	10.04
10.29*	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1
10.30+	Aircraft Time Sharing Agreement, effective Feb. 25, 2025, between Xcel Energy Services Inc., as Operator, and the Chief Executive Officer of Operator		
10.31*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association., as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.01
19.1	Securities Trading Overall Policy		
19.2	Securities Trading for Pre-Clearance Persons Policy		
NSP-Minnesota			

4.14*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(3)
4.15*	Supplemental Trust Indenture, dated as of June 1, 1995, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $250 million aggregate principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.11
4.16*	Supplemental Trust Indenture, dated as of March 1, 1998, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $150 million aggregate principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.12
4.17*	Supplemental Trust Indenture, dated as of Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.18*	Supplemental Trust Indenture, dated as of July 1, 2005, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $250 million aggregate principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.19*	Supplemental Trust Indenture, dated as of May 1, 2006, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $400 million aggregate principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.20*	Supplemental Trust Indenture, dated as of June 1, 2007, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $350 million aggregate principal amount of 6.20% First Mortgage Bonds, Series due July 1, 2037	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.21*	Supplemental Trust Indenture, dated as of Nov. 1, 2009, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company., NA, as Trustee, creating $300 million aggregate principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.22*	Supplemental Trust Indenture, dated as of Aug. 1, 2010, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $250 million aggregate principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.23*	Supplemental Trust Indenture, dated as of Aug. 1, 2012, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $500 million aggregate principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.24*	Supplemental Trust Indenture, dated as of May 1, 2014, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.25*	Supplemental Trust Indenture, dated as of Aug. 1, 2015, by and between NSP-Minnesota and The Bank of New York Mellon Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.26*	Supplemental Trust Indenture, dated as of May 1, 2016, by and between NSP-Minnesota and The Bank of NY Mellon Trust Company, N.A., as Trustee, creating $350 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.27*	Supplemental Trust Indenture, dated as of Sept. 1, 2017, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01
4.28*	Supplemental Trust Indenture, dated as of Sept. 1, 2019, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.29*	Supplemental Indenture, dated as of June 8, 2020, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $700 million aggregate principal amount of 2.60% First Mortgage Bonds, Series due June 1, 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
4.30*	Supplemental Indenture, dated as of March 1, 2021, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $425 million principal amount of 2.25% First Mortgage Bonds, Series due April 1, 2031 and $425 million principal amount of 3.20% First Mortgage Bonds, Series due April 1, 2052	NSP-Minnesota 8-K dated March 30, 2021	4.01
4.31*	Supplemental Indenture, dated as of May 1, 2022, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $500 million aggregate principal amount of 4.50% First Mortgage Bonds, Series due June 1, 2052	NSP-Minnesota 8-K dated May 9, 2022	4.01
4.32*	Supplemental Trust Indenture dated as of May 1, 2023 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $800 million aggregate principal amount of 5.10% First Mortgage Bonds, Series due May 15, 2053.	NSP-Minnesota 8-K dated May 8, 2023	4.01
4.33*	Supplemental Trust Indenture dated as of February 1, 2024 between Northern States Power Company and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $700,000,000 aggregate principal amount of 5.40% First Mortgage Bonds, Series due March 15, 2054.	NSP-Minnesota Form 8-K dated February 29, 2024	4.01
10.32*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.33*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.02
NSP-Wisconsin			
4.34*	Supplemental and Restated Trust Indenture, dated as of March 1, 1991, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to First Wisconsin Trust Company), as Trustee providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(c)(3)
4.35*	Trust Indenture, dated Sept. 1, 2000, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to Firstar Bank, N.A.), as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	4.01
4.36*	Supplemental Trust Indenture, dated as of Sept. 1, 2008, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	4.01
4.37*	Supplemental Trust Indenture, dated as of Oct. 1, 2012, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	4.01

4.38*	Supplemental Trust Indenture, dated as of Nov 1, 2017, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	4.01
4.39*	Supplemental Indenture, dated as of Sept. 1, 2018, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin Form 8-K dated Sept. 12, 2018	4.01
4.40*	Supplemental Trust Indenture, dated as of May 18, 2020, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.05% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated May 26, 2020	4.01
4.41*	Supplemental Indenture dated as of July 19, 2021 between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million principal amount of 2.82% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated July 20, 2021	4.01
4.42*	Supplemental Trust Indenture, dated as of July 15, 2022, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association, as Trustee, creating $100 million aggregate principal amount of 4.86% First Mortgage Bonds, Series due Sept. 15, 2052	NSP-Wisconsin Form 8-K dated July 15, 2022	4.01
4.43*	Supplemental Indenture dated as of May 10, 2023 between NSP-Wisconsin and U.S. Bank Trust Company, National Association, as successor Trustee, creating 5.30% First Mortgage Bonds, Series due June 15, 2053	NSP-Wisconsin Form 8-K dated May 10, 2023	4.01
4.44*	Supplemental Indenture dated as of May 13, 2024 between Northern States Power Company and U.S. Bank Trust Company, National Association, as successor Trustee, creating $400 million principal amount of 5.65% First Mortgage Bonds, Series due June 15, 2054	NSP-Wisconsin Form 8-K dated May 16, 2024	4.01
10.34*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.35*	Fourth Amended and Restated Credit Agreement, dated as of Sept. 19, 2022, among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd. and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.05
PSCo			
4.45*	Indenture, dated as of Oct. 1, 1993, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to Morgan Guaranty Trust Company of New York), as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(d)(3)
4.46*	Supplemental Indenture No. 17, dated as of Aug. 1, 2007, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $350 million of 6.25% First Mortgage Bonds, Series No. 17 due Sept. 1, 2037	PSCo Form 8-K dated Aug. 8, 2007	4.01
4.47*	Supplemental Indenture No. 18, dated as of Aug. 1, 2008, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 6.50% First Mortgage Bonds, Series No. 19 due Aug. 1, 2038	PSCo Form 8-K dated Aug. 6, 2008	4.01
4.48*	Supplemental Indenture No. 21, dated as of Aug. 1, 2011, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 4.75% First Mortgage Bonds, Series No. 22 due Aug. 15, 2041	PSCo Form 8-K dated Aug. 9, 2011	4.01
4.49*	Supplemental Indenture No. 22, dated as of Sept. 1, 2012, between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $500 million aggregate principal amount of 3.60% First Mortgage Bonds, Series No. 24 due Sept. 15, 2042	PSCo Form 8-K dated Sept. 11, 2012	4.01
4.50*	Supplemental Indenture No. 24, dated as of March 1, 2014, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 4.30% First Mortgage Bonds, Series No. 27 due March 15, 2044	PSCo Form 8-K dated March 10, 2014	4.01
4.51*	Supplemental Indenture No. 25, dated as of May 1, 2015, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 2.90% First Mortgage Bonds, Series No. 28 due May 15, 2025	PSCo Form 8-K dated May 12, 2015	4.01
4.52*	Supplemental Indenture No. 26, dated as of June 1, 2016, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 3.55% First Mortgage Bonds, Series No. 29 due June 15, 2046	PSCo Form 8-K dated June 13, 2016	4.01
4.53*	Supplemental Indenture No. 27, dated as of June 1, 2017, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $400 million aggregate principal amount of 3.80% First Mortgage Bonds, Series No. 30 due June 15, 2047	PSCo Form 8-K dated June 19, 2017	4.01
4.54*	Supplemental Indenture No. 28, dated as of June 1, 2018, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $350 million aggregate principal amount of 3.70% First Mortgage Bonds, Series No. 31 due June 15, 2028, and $350 million aggregate principal amount of 4.10% First Mortgage Bonds, Series No. 32 due June 15, 2048	PSCo Form 8-K dated June 21, 2018	4.01
4.55*	Supplemental Indenture No. 29, dated as of March 1, 2019, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $400 million aggregate principal amount of 4.05% First Mortgage Bonds, Series No. 33 due Sept. 15, 2049	PSCo Form 8-K dated March 13, 2019	4.01
4.56*	Supplemental Indenture No. 30, dated as of Aug. 1, 2019, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $550 million aggregate principal amount of 3.20% First Mortgage Bonds, Series No. 34 due March 1, 2050	PSCo Form 8-K dated August 13, 2019	4.01
4.57*	Supplemental Indenture No. 31, dated as of May 1, 2020, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $375 million aggregate principal amount of 2.70% First Mortgage Bonds, Series No. 35 due Jan. 15, 2051 and $375 million aggregate principal amount of 1.90% First Mortgage Bonds, Series No. 36 due Jan. 15, 2031	PSCo Form 8-K dated May 15, 2020	4.01
4.58*	Supplemental Indenture No. 32, dated as of February 1, 2021, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $750 million aggregate principal amount of 1.875% First Mortgage Bonds, Series No. 37 due June 15, 2031	PSCo Form 8-K dated March 1, 2021	4.01
4.59*	Supplemental Indenture No. 33, dated as of May 1, 2022, by and between PSCo and U.S. Bank Trust Company, National Association, as Trustee, creating $300 million aggregate principal amount of 4.10% First Mortgage Bonds, Series No. 38 due June 1, 2032 and $400 million aggregate principal amount of 4.50% First Mortgage Bonds, Series No. 39 due June 1, 2052	PSCo Form 8-K dated May 17, 2022	4.01

4.60*	Supplemental Indenture No. 34, dated as of March 1, 2023, between PSCo and U.S. Bank Trust Company, National Association, as successor Trustee, creating $850 million principal amount of 5.25% First Mortgage Bonds, Series No. 40 due April 1, 2053.	PSCo Form 8-K dated April 3, 2023	4.01
4.61*	Supplemental Indenture dated as of April 1, 2024, between Public Service Company of Colorado and U.S. Bank Trust Company, National Association, as successor Trustee, creating $450 million principal amount of 5.35% First Mortgage Bonds, Series No. 41 due 2034 and $750 million principal amount of 5.75% First Mortgage Bonds, Series No. 42 due 2054.	PSCo Form 8-K dated April 4, 2024	4.01
10.36*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.03
SPS			
4.62*	Indenture, dated as of Feb. 1, 1999, by and between SPS and The Chase Manhattan Bank, as Trustee	SPS Form 8-K dated Feb. 25, 1999	99.2
4.63*	Third Supplemental Indenture, dated as of Oct. 1, 2003, by and between SPS and JPMorgan Chase Bank (as successor to The Chase Manhattan Bank), as Trustee, creating $100 million aggregate principal amount of Series C Notes, 6% due Oct. 1, 2033 and Series D Notes, 6% due Oct. 1, 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.64*	Fourth Supplemental Indenture, dated as of Oct. 1, 2006, by and between SPS and The Bank of New York (as successor to The Chase Manhattan Bank), as Trustee, creating $250 million aggregate principal amount of Series F Notes, 6% due Oct. 1, 2036	SPS Form 8-K dated Oct. 3, 2006	4.01
4.65*	Indenture, dated as of Aug. 1, 2011, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01
4.66*	Supplemental Indenture No. 1, dated as of Aug. 3, 2011, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 4.50% First Mortgage Bonds, Series No. 1 due Aug. 15, 2041	SPS Form 8-K dated Aug. 10, 2011	4.02
4.67*	Supplemental Indenture No. 4, dated as of Aug. 1, 2016, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 3.40% First Mortgage Bonds, Series No. 4 due Aug. 15, 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.68*	Supplemental Indenture No. 5, dated as of Aug. 1, 2017, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $450 million aggregate principal amount of 3.70% First Mortgage Bonds, Series No. 5 due Aug. 15 2047	SPS Form 8-K dated Aug 9. 2017	4.02
4.69*	Supplemental Indenture No. 6, dated as of Oct. 1, 2018, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 4.40% First Mortgage Bonds, Series No. 6 due Nov. 15, 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.70*	Supplemental Indenture No. 7, dated as of June 1, 2019, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 3.75% First Mortgage Bonds, Series No. 7 due June 15, 2049	SPS Form 8-K dated June 18, 2019	4.02
4.71*	Supplemental Indenture No. 8, dated as of May 1, 2020, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $600 million aggregate principal amount of 3.15% First Mortgage Bonds, Series No. 8 due May 1, 2050	SPS Form 8-K dated May 18, 2020	4.02
4.72*	Supplemental Indenture No. 9, dated as of May 1, 2022, by and between SPS and U.S. Bank Trust Company, National Association, as Trustee, creating $200 million aggregate principal amount of 5.15% First Mortgage Bonds, Series No. 9 due June 1, 2052	SPS Form 8-K dated May 31, 2022	4.02
4.73*	Supplemental Indenture No. 10 dated as of August 21, 2023 between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 6.00% First Mortgage Bonds, Series No. 10 due 2053.	SPS Form 8-K dated August 21, 2023	4.01
4.74*	Supplemental Indenture No. 11 dated as of May 15, 2024 between Southwestern Public Service Company and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $600 million principal amount of 6.00% First Mortgage Bonds, Series No. 11 due 2054	SPS Form 8-K dated June 6, 2024	4.02
10.37*	Fourth Amended and Restated Credit Agreement, dated as of Sept. 19, 2022, among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd. and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.04
Xcel Energy Inc.			
21.01	Subsidiaries of Xcel Energy Inc.		
23.01	Consent of Independent Registered Public Accounting Firm		
24.01	Powers of Attorney		
31.01	Principal Executive Officer's certification 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 certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
97.01	Mandatory Compensation Recovery Policy for Section 16 Officers		
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)		

SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2024	2023	2022
Income			
Equity earnings of subsidiaries	$ 2,122	$ 1,948	$ 1,905
Total income	2,122	1,948	1,905
Expenses and other deductions			
Operating expenses	24	25	19
Other income	(76)	(13)	(2)
Interest charges and financing costs	300	235	206
Total expenses and other deductions	248	247	223
Income before income taxes	1,874	1,701	1,682
Income tax benefit	(62)	(70)	(54)
Net income	$ 1,936	$ 1,771	$ 1,736
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax	$ 2	$ (2)	$ 9
Derivative instruments, net of tax	24	1	21
Other comprehensive income (loss)	26	(1)	30
Comprehensive income	$ 1,962	$ 1,770	$ 1,766
Weighted average common shares outstanding:			
Basic	563	552	547
Diluted	563	552	547
Earnings per average common share:			
Basic	$ 3.44	$ 3.21	$ 3.18
Diluted	3.44	3.21	3.17

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2024	2023
Assets		
Cash and cash equivalents	$ 16	$ 24
Accounts receivable from subsidiaries, net	410	404
Other current assets	9	5
Total current assets	435	433
Investment in subsidiaries	26,519	23,873
Investment in debt securities — intercompany	166	—
Other assets	6	(20)
Total other assets	26,691	23,853
Total assets	$ 27,126	$ 24,286
Liabilities and Equity		
Current portion of long-term debt	600	—
Dividends payable	314	289
Short-term debt	235	165
Other current liabilities	90	66
Total current liabilities	1,239	520
Other liabilities	28	12
Total other liabilities	28	12
Commitments and contingencies		
Capitalization		
Long-term debt	6,337	6,137
Common stockholders' equity	19,522	17,617
Total capitalization	25,859	23,754
Total liabilities and equity	$ 27,126	$ 24,286

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2024	2023	2022
Operating activities			
Net cash provided by operating activities	$ 1,459	$ 1,586	$ 1,340
Investing activities			
Capital contributions to subsidiaries	(2,184)	(975)	(921)
Investment in debt securities — intercompany	(105)	—	—
Net return in the utility money pool	21	21	—
Net cash used in investing activities	(2,268)	(954)	(921)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	70	(66)	(407)
Proceeds from issuance of long-term debt	795	792	694
Repayment of long-term debt	—	(500)	—
Proceeds from issuance of common stock	1,117	270	322
Dividends paid	(1,175)	(1,092)	(1,012)
Other	(6)	(13)	(16)
Net cash provided by (used in) financing activities	801	(609)	(419)
Net change in cash, cash equivalents, and restricted cash	(8)	23	—
Cash, cash equivalents and restricted cash at beginning of period	24	1	1
Cash, cash equivalents and restricted cash at end of period	$ 16	$ 24	$ 1

See Notes to Condensed Financial Statements

Notes to Condensed Financial Statements

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and other comprehensive income in Part II, Item 8.

Basis of Presentation

The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2024 and 2023, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2024:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantees of Capital Services purchase contracts for wind and solar generating equipment	Xcel Energy Inc.	951	(a)	(b)
Guarantees of Xcel Energy Services Inc. performance and payments on operating lease agreements	Xcel Energy Inc.	29	29	(b)
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries (c)	Xcel Energy Inc.	93	(d)	(e)

(a) Given that the manufacturing of equipment has not yet commenced, related exposure to the performance obligations of Capital Services at Dec. 31, 2024 has been assessed as immaterial.
(b) Nonperformance and/or nonpayment.
(c) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.
(d) Due to the number of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.
(e) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions

Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable net of payables with affiliates at Dec. 31:

(Millions of Dollars)	2024	2023
NSP-Minnesota	$ 79	$ 120
NSP-Wisconsin	11	13
PSCo	77	44
SPS	41	47
Xcel Energy Services Inc.	163	144
Other subsidiaries of Xcel Energy Inc.	39	35
	$ 410	$ 403

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,685 million, $1,693 million and $1,503 million for the years ended Dec. 31, 2024, 2023 and 2022, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool **—** FERC approval was received 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.

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2024	Year Ended Dec. 31, 2023	Year Ended Dec. 31, 2022
Loan outstanding at period end	$ —	$ 21	$ —
Average loan outstanding	18	27	10
Maximum loan outstanding	209	250	204
Weighted average interest rate, computed on a daily basis	5.34 %	5.33 %	0.73 %
Weighted average interest rate at end of period	5.34	5.34	N/A
Money pool interest income	$ 1	$ 1	$ —

There were no money pool activities for quarter ended December 31, 2024.

During 2024, Xcel Energy Inc. purchased $166 million in aggregate principal amounts of NSP-Minnesota's 2.60% First Mortgage Bonds Series due June 1, 2051 for $105 million.

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2024	2023	2022	2024	2023	2022
Balance at Jan. 1	$ 128	$ 122	$ 106	$ 70	$ 62	$ 64
Additions charged to costs and expenses	64	79	73	45	26	6
Additions charged to other accounts	16 (a)	13 (a)	26 (a)	—	—	—
Deductions from reserves	(97) (b)	(86) (b)	(83) (b)	(42) (c)	(18) (c)	(8) (c)
Balance at Dec. 31	$ 111	$ 128	$ 122	$ 73	$ 70	$ 62

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.
(c) Primarily reversals of valuation allowances on completed tax credit sales and reductions of valuation allowances for items forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

		XCEL ENERGY INC.
Feb. 27, 2025	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ MELISSA L. OSTROM Melissa L. Ostrom	Senior Vice President, Controller (Principal Accounting Officer)
*	Megan Burkhart	Director
*	Lynn Casey	Director
*	Netha Johnson	Director
*	Patricia L. Kampling	Director
*	George J. Kehl	Director
*	Richard T. O'Brien	Director
*	Charles Pardee	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	Devin Stockfish	Director
*	Timothy Welsh	Director
*	Kim Williams	Director
*	Daniel Yohannes	Director
*By:	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Attorney-in-Fact