

XCEL ENERGY INC
Form 10-K
February 22, 2019

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, 2018

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

001-3034 41-0448030
(Commission File Number) (I.R.S. Employer Identification No.)

(Registrant,
State of
Incorporation

or
Organization,
Address of
Principal

Executive
Officers and
Telephone
Number)

Xcel Energy
Inc.

(a Minnesota
corporation)

414 Nicollet
Mall

Minneapolis,
MN 55401

612-330-5500

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

Title of each class

Common Stock, \$2.50 par value per share

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

Name of each exchange on which
registered

Nasdaq Stock Market LLC

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

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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 and 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 if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller Reporting Company ☐ Emerging growth company
If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of June 29, 2018, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was \$23,246,479,826 and there were 508,898,420 shares of common stock outstanding.

As of Feb. 14, 2019, there were 514,211,368 shares of common stock outstanding, \$2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2019 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

ABBREVIATIONS AND INDUSTRY TERMS

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

Capital Services Capital Services, LLC

Eloigne Eloigne Company

e prime e prime inc.

NCE New Century Energies, Inc.

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

Operating companies NSP-Minnesota, NSP-Wisconsin, PSCo and SPS

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

D.C. Circuit United States Court of Appeals for the District of Columbia Circuit

DOC Minnesota Department of Commerce

DOE United States Department of Energy

DOJ Department of Justice

DOT United States Department of Transportation

EPA United States Environmental Protection Agency

FERC Federal Energy Regulatory Commission

Fifth Circuit United States Court of Appeals for the Fifth Circuit

IRS Internal Revenue Service

Minnesota District Court U.S. District Court for the District of Minnesota

MPSC Michigan Public Service Commission

MPUC Minnesota Public Utilities Commission

NDPSC North Dakota Public Service Commission

NERC North American Electric Reliability Corporation

Ninth Circuit U.S. Court of Appeals for the Ninth Circuit

NMPRC New Mexico Public Regulation Commission

NRC Nuclear Regulatory Commission

OAG Minnesota Office of the 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 Utilities Commission

SEC Securities and Exchange Commission

TCEQ Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment

Clauses

CIP Conservation improvement program

DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor
WCA	Windsor [®] cost adjustment
Other	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARAM	Average rate assumption method
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
ATM	At-the-market
ATRR	Annual transmission revenue requirement
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CAPM	Capital Asset Pricing Model
CACJA	Clean Air Clean Jobs Act
CAISO	California Independent System Operator
CapX2020	Alliance of electric cooperatives, municipalities and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CBA	Collective-bargaining agreement
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
CEP	Colorado Energy Plan
CIG	Colorado Interstate Gas Company, LLC

CO ₂	Carbon dioxide
Corps	U.S. Army Corps of Engineers
CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CWA	Clean Water Act

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CWIP	Construction work in progress
DCF	Discounted Cash Flows
DECON	Decommissioning method where radioactive contamination is removed and safely disposed at a requisite facility, or decontaminated to a permitted level.
DRC	Development Recovery Company
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
EPU	Extended power uprate
ERP	Electric resource plan
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
HTY	Historic test year
IM	Integrated market
IPP	Independent power producing entity
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
JOA	Joint operating agreement
LCM	Life cycle management
LLW	Low-level radioactive waste
LSP	LSP Transmission Holdings, LLC
Transmission	
Mankato 1	Mankato Energy Center, LLC
Mankato 2	Mankato Energy Center II, LLC
MDL	Multi-district litigation
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
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.
NETO	New England Transmission Owners
NOL	Net operating loss
NOX	Nitrogen oxide
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
Opinion 531	Methodology for calculating base ROE adopted by the FERC in June 2014

Paris Agreement	Establishes a framework for GHG mitigation actions by all countries (“nationally determined contributions”)
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PRP	Potentially responsible party
PTC	Production tax credit
QF	Qualifying facilities
R&E	Research and experimentation
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity
ROFR	Right-of-first-refusal
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
Standard & Poor’s	Standard & Poor’s Ratings Services
SAB	Staff Accounting Bulletin
SAB 118	Income Tax Accounting Implications of the Tax Cuts and Jobs Act
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO ₂	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SSL	Statistically significant increase over established groundwater standards
TCEH	Texas Competitive Energy Holdings
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
TOs	Transmission owners
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity
WOTUS	Waters of the U.S.
Measurements	
Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2019 EPS guidance, long-term EPS and dividend growth rate, 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, 2018 (including the items described under Factors Affecting Results of Operations; and the other 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 hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; climate change and other weather, natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; ability of subsidiaries to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers’ and counterparties’ ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries’ ability to make dividend payments; tax laws; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

Where To Find More Information

Xcel Energy’s website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, 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>.

COMPANY OVERVIEW

Xcel Energy Inc. and its subsidiaries (“Xcel Energy” or the “Company”) is a major U.S. regulated electric and natural gas delivery company which serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. The Company provides a comprehensive portfolio of energy-related products and services to approximately 3.6 million electric customers and 2.0 million natural gas customers through four operating companies (e.g., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS).

Xcel Energy’s vision is to be the preferred and trusted provider of the energy our customers need and we strive to provide our investors an attractive total return value proposition and customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep the bills low.

Xcel Energy is an environmental leader and in 2018 was the first major utility in the nation to announce a vision to serve all customers with 100% zero-carbon emissions by 2050. The Company is also implementing the nation’s largest multi-state wind plan with 12 new, low-cost wind farms across seven states. By leading the clean energy transition, we have positioned ourselves to create economic development for the communities and customers we serve. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Management’s Strategic Priorities for further discussion.

* Holding company incorporated under the laws of Minnesota in 1909 and its executive offices are located at 414 Nicollet Mall, Minneapolis, MN 55401.

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NSP-Minnesota

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 as 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-Minnesota

Electric customers	1.5 million
Natural gas customers	0.5 million
Consolidated earnings contribution	35% to 45%
Total assets	\$18.5 billion
Electric generating capacity	7,530 MW
Gas storage capacity	14.7 Bcf

NSP-Wisconsin

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

NSP-Wisconsin

Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution	5% to 10%
Total assets	\$2.7 billion
Electric generating capacity	563 MW
Gas storage capacity	3.6 Bcf

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PSCo

PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity in addition to purchasing, transporting, distributing and selling natural gas to retail customers and transporting customer-owned natural gas.

PSCo

Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution	35% to 45%
Total assets	\$17.3 billion
Electric generating capacity	5,685 MW
Gas storage capacity	27.1 Bcf

SPS

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

SPS

Electric customers	0.4 million
Consolidated earnings contribution	15% to 20%
Total assets	\$6.7 billion
Electric generating capacity	4,406 MW

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ELECTRIC UTILITY OPERATIONS

Electric Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Electric sales (Millions of KWh)			
Residential	25,518	24,216	24,726
Large C&I	28,686	27,951	27,664
Small C&I	36,308	35,493	35,830
Public authorities and other	1,071	1,055	1,103
Total retail	91,583	88,715	89,323
Sales for resale	24,199	18,349	18,694
Total energy sold	115,782	107,064	108,017
Number of customers at end of period			
Residential	3,117,262	3,082,974	3,053,732
Large C&I	1,253	1,241	1,228
Small C&I	436,836	433,883	432,012
Public authorities and other	69,794	69,376	68,935
Total retail	3,625,145	3,587,474	3,555,907
Wholesale	70	58	52
Total customers	3,625,215	3,587,532	3,555,959
Electric revenues (Millions of Dollars)			
Residential	\$3,006	\$ 2,975	\$ 2,966
Large C&I	1,696	1,779	1,707
Small C&I	3,343	3,463	3,328
Public authorities and other	136	143	140
Total retail	8,181	8,360	8,141
Wholesale	801	719	693
Other electric revenues	737	597	666
Total electric revenues	\$9,719	\$ 9,676	\$ 9,500
KWh sales per retail customer	25,263	24,729	25,120
Revenue per retail customer	\$2,257	\$ 2,330	\$ 2,289
Residential revenue per KWh	11.78¢	12.29 ¢	11.99 ¢
Large C&I revenue per KWh	5.91	6.36	6.17
Small C&I revenue per KWh	9.21	9.76	9.29
Total retail revenue per KWh	8.93	9.42	9.11
Wholesale revenue per KWh	3.31	3.92	3.71

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Energy Sources 2018

*Distributed generation from the Solar*Rewards® program is not included (approximately 432 million KWh for 2018).

Energy Source Statistics

	Xcel Energy		NSP System		PSCo		SPS	
2018								
Owned Generation	67	%	77	%	70	%	49	%
Purchased Generation	33		23		30		51	
	100	%	100	%	100	%	100	%
2017								
Owned Generation	66	%	75	%	70	%	47	%
Purchased Generation	34		25		30		53	
	100	%	100	%	100	%	100	%

Renewable Sources

Xcel Energy's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2018, each utility or system was in compliance with their applicable RPS. Renewable percentages will vary year over year based on local weather, system demand and transmission constraints.

NSP System

Renewable energy as a percentage of the NSP System's total:

	2018	2017
Wind	16.4%	18.3%
Hydroelectric	5.8	6.3
Biomass and solar	4.8	4.2
Renewable	27.0%	28.8%

Wind — The NSP System has more than 130 PPAs ranging from under one MW to more than 200 MW. The NSP System owns and operates five wind farms with 840 MW, net, of capacity.

The NSP System had approximately 2,550 MW and 2,600 MW of wind energy on its system at the end of 2018 and 2017, respectively.

Average cost per MWh of wind energy under existing PPAs was approximately \$44 for 2018 and 2017.

Average cost per MWh of wind energy from owned generation was approximately \$37 and \$42 for 2018 and 2017, respectively.

PSCo

Renewable energy as a percentage of PSCo's total:

	2018	2017
Wind	23.8%	23.7%
Hydroelectric and solar	3.6	3.9
Renewable	27.4%	27.6%

Wind — PSCo has 19 PPAs ranging from two MW to over 300 MW. PSCo owns and operates the Rush Creek wind farm which has 600 MW, net, of capacity.

PSCo had approximately 3,160 MW and 2,560 MW of wind energy on its system at the end of 2018 and 2017, respectively.

Average cost per MWh of wind energy under these contracts was approximately \$43 and \$42 for 2018 and 2017, respectively.

Rush Creek became operational in December 2018. The 2019 average cost per MWh is expected to be \$29.
SPS

Renewable energy as a percentage of SPS' total:

	2018	2017
Wind	19.1 %	21.2 %
Solar	2.0	2.8
Renewable	21.1 %	24.0 %

Wind — SPS has 18 PPAs with facilities ranging from under one MW to 250 MW.

SPS had approximately 1,565 MW and 1,500 MW of wind energy on its system at the end of 2018 and 2017, respectively.

Average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately \$26 and \$27 for 2018 and 2017, respectively.

In 2018, SPS began construction on the Sagamore and Hale County wind farms. Refer to the SPS Wind Development section for further information.

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Non-Renewable Sources

Delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation and the percentage of total fuel requirements represented by each category of fuel:

	Coal ^(a)		Nuclear		Natural Gas	
	Cost	Percent	Cost	Percent	Cost	Percent
NSP System						
2018	\$2.13	42 %	\$0.80	45 %	\$3.87	13 %
2017	2.08	45	0.78	45	4.10	10
PSCo						
2018	1.45	62	—	—	3.74	38
2017	1.56	70	—	—	3.82	30
SPS						
2018	2.04	56	—	—	2.24	44
2017	2.18	74	—	—	3.39	26

^(a) Includes refuse-derived fuel and wood for the NSP System.

Weighted average cost per MMBtu of all fuels for owned electric generation:

	NSP System	PSCo	SPS
2018	\$ 1.78	\$2.33	\$2.13
2017	1.72	2.25	2.50

See Items 1A and 7 for further information.

Coal — Inventory maintained (in days):

	Normal	Dec. 31, 2018 Actual	Dec. 31, 2017 Actual ^(a)
NSP System	35 - 50	47	53
PSCo	35 - 50	48	48
SPS	35 - 50	44	52

^(a) Milder weather, purchase commitments and low power and natural gas prices impacted coal inventory levels.

Coal requirements (in million tons):

	2018	2017
NSP System	7.8	8.0
PSCo	9.4	10.0
SPS	5.1	5.5

Coal supply as a percentage of requirements (in million tons) for 2019:

	Contracted Coal Supply	2019 Estimated Requirements
NSP System ^(a)	76%	^(b) 8.4
PSCo ^(a)	83	8.4
SPS ^(a)	64	4.1

^(a) The general coal purchasing objective is to contract for approximately 75% of first year requirements, 40% of year two requirements and 20% of year three requirements.

^(b) Increase in estimated million tons was due to lower delivered coal prices at Sherco in January 2019, combined with higher future forecasted gas prices for 2019 (higher burn forecast).

Contracted coal transportation as a percentage of requirements in 2019 and 2020:

	2019	2020
NSP System	100%	100%
PSCo	100	100
SPS	100	100

Natural Gas — 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. Contracts and commitments at Dec. 31:

(Millions of Dollars)	NSP System	PSCo		SPS	
	Gas Transportation and Storage (a)	Gas Supply (b)	Gas Transportation and Storage (a)	Gas Supply	Gas Transportation and Storage (a)
2018	\$406	\$412	\$589	\$20	\$152
2017	—398	545	620	11	191
Year of Expiration	N/A 2020 - 2037	2021 - 2019 - 2040 2023		One year or less	2019 - 2033

(a) For incremental supplies, there are limited on-site fuel storage facilities, with a primary reliance on the spot market. Majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services

(b) Company and the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 10 to the consolidated financial statements for further information.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Current nuclear fuel supply contracts cover 100% of uranium concentrates requirements through 2021 and approximately 51% of the requirements for 2022 - 2033.

Current contracts for conversion services cover 100% of the requirements through 2021 and approximately 43% of the requirements for 2022 - 2033.

Current enrichment service contracts cover 100% of the requirements through 2025 and approximately 19% of the requirements for 2026 - 2033.

Fabrication services for Monticello and PI are 100% committed through 2030 and 2027, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the requirements of its nuclear generating plants. Some exposure to market price volatility will remain due to index-based pricing structures contained in supply contracts.

See Item 7 for further information.

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Capacity and Demand

Uninterrupted system peak demand and date for the regulated utilities:

	System Peak Demand (in MW)	
	2018	2017
NSP System ^(a)	8,927 June 29	8,546 July 17
PSCo ^(a)	6,718 July 10	6,671 July 19
SPS ^(a)	4,648 July 19	4,374 July 26

^(a) Peak demand typically occurs in the summer. The increase in peak load from 2017 to 2018 is partly due to warmer weather in 2018.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, NDPSC and SDPUC. The MPUC also has regulatory authority over security issuances, certain property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's IRPs for meeting future energy needs. In addition, MPUC certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC for its 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. NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and MISO 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.

Fuel, Purchased Energy and Conservation Cost-Recovery

Mechanisms —

• CIP rider — Recovers the costs of conservation and demand-side management programs.

• EIR — Recovers the costs of environmental improvement projects.

• RDF — Allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.

• RES — Recovers the cost of renewable generation in Minnesota.

• RER — Recovers the cost of renewable generation located in North Dakota.

• SEP — Recovers costs related to various energy policies approved by the Minnesota legislature.

• TCR — Recovers costs associated with investments in electric transmission and distribution grid modernization costs.

• Infrastructure rider — Recovers costs for investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. Costs associated with MISO are generally recovered through either the FCA or base rates.

In 2017, the MPUC voted to change the FCA process in Minnesota. Under the new process, each month utilities would collect amounts equal to the baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Utilities would issue refunds above the baseline costs, and could seek recovery of any overage. Recently, the MPUC delayed implementation until January 2020.

Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

Energy Sources and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. 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.

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation.

In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range, a 300 MW wind project in South Dakota. NSP-Minnesota's capital investment for the Dakota Range is expected to be approximately \$350 million and placed in service in 2021.

In December 2018, the NDPSC approved a settlement agreement for these wind development projects.

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a \$103 million regulatory asset was recognized for the costs of the Benson transaction. For Laurentian, a regulatory asset of \$109 million was recognized for annual termination payments/obligations. Regulatory approvals provide for recovery of the Benson regulatory asset over 10 years and Laurentian termination payments as they occur (over six years). Termination of the PPAs is expected to save customers over \$600 million throughout the next 10 years.

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Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. Docket remains under consideration by the NDPSC.

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minnesota to Winnebago, Minnesota. The project was estimated by MISO to cost \$108 million and was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. It is uncertain when a decision will be rendered.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

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 in customer rates and expects future compliance costs will continue to be recoverable.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and the Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose 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. The federal government has been evaluating a nuclear geologic repository at Yucca Mountain, Nevada for many years. Currently, there are no definitive plans for a permanent federal storage facility at Yucca Mountain or any other site.

Review of PI Costs — As part of NSP-Minnesota's 2016 multi-year electric rate case and IRP, the MPUC ordered an investigation into NSP-Minnesota's PI nuclear investments. The issue was resolved as part of the 2016 multi-year electric rate case settlement. In November 2018, the DOC issued a final report, in which no cost disallowances were recommended.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. 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.

In 2013, NSP-Minnesota's Monticello nuclear generating plant loaded and placed five storage canisters (canisters #11-15) in the ISFSI and a sixth canister (canister #16) was loaded but remained in the plant pending resolution of weld inspection issues. Successful pressure and leak testing demonstrated the safety and integrity of all six canisters

involved. NSP-Minnesota took several actions to assure compliance with the NRC's regulations and Monticello's storage license. The NRC has approved NSP-Minnesota's compliance plan for all canisters.

NSP-Minnesota intends to seek recovery of these costs in a future regulatory proceeding. No public safety issues have been raised, or are believed to exist, in this matter.

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

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various 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 and credit risk and hedge sales and purchases. NSP-Minnesota also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC for its 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. 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.

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.

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Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the fuel cost 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 utility's most recently authorized ROE. Fuel cost under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.

NSP-Wisconsin's electric fuel costs for 2018 were lower than authorized in rates and outside the 2% annual tolerance band, primarily due to greater than forecasted generation sales into the MISO market and lower purchased power costs coupled with moderate weather. Under the fuel cost recovery rules, NSP-Wisconsin retained approximately \$3.6 million of fuel costs and deferred approximately \$2.8 million. NSP-Wisconsin will file a reconciliation of 2018 fuel costs with the PSCW by March 31, 2019.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are 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.

Wisconsin Energy Efficiency Program — The primary energy efficiency program is funded by the state's utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from retail customers.

Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota-Energy Sources and Transmission Service Provider.

NSP-Wisconsin / American Transmission Company, LLC - La Crosse to Madison, WI Transmission Line — In December 2018, construction was completed on the Badger Coulee 345 KV transmission line. The line extends from La Crosse, WI. to Madison, WI. NSP-Wisconsin's half of the line is shared with Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC for its 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. 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. PSCo makes 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 as authorized by the FERC.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms

ECA — Recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.

PCCA — Recovers purchased capacity payments.

SCA — Recovers the difference between PSCo's actual cost of fuel and costs recovered under its steam service rates. The SCA rate is revised quarterly.

DSMCA — Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.

RESA — Recovers the incremental costs of compliance with the RES with a maximum of 2% of the customer's bill.

WCA — Recovers costs for customers who choose renewable resources.

☛TCA — Recovers costs for transmission investment outside of rate cases.

☛CACJA — Recovers costs associated with the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

Energy Sources and Transmission Service Providers

PSCo expects to meet its system capacity requirements through electric generating stations, power purchases, new generation facilities, DSM options and expansion of generation plants.

Purchased Power — PSCo purchases power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. It also contracts to purchase power for both wind and solar resources. PSCo makes short-term purchases to meet system load and energy requirements, replace owned generation, 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.

Wind Development — In 2018, PSCo completed construction and placed in service its Rush Creek 600 MW wind farm in Colorado.

CEP — In September 2018, the CPUC approved PSCo's preferred CEP portfolio, which included the retirement of two coal-fired generation units, Comanche Unit 1 (in 2022) and Comanche Unit 2 (in 2025), and the following additions:

	Total Capacity	PSCo's Ownership
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

PSCo's investment is expected to be approximately \$1 billion, including transmission to support the increase in renewable generation. This investment includes the 500 MW Cheyenne Ridge wind farm and 345 KV generation tie line, as well as the Shortgrass Substation. CPCNs for these projects were filed in December 2018. A CPUC decision is anticipated by May 2019. CPCNs for the natural gas generation facility are anticipated to be filed by mid-2019.

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Boulder Municipalization — In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Subsequently, there have been various legal proceedings in multiple venues with jurisdiction over Boulder’s plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility and the Colorado Court of Appeals ruled in PSCo’s favor, vacating a lower court decision. In June 2018, the Colorado Supreme court rejected Boulder’s request to dismiss the case and remanded it to the Boulder District Court.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo’s position. The CPUC has approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings. Those filings were submitted in the fourth quarter of 2018. Subsequently, various parties requested the CPUC commence additional processes; the form of such processes is currently under consideration. In the fourth quarter of 2018, Boulder’s City Council also adopted an Ordinance authorizing Boulder to begin negotiations for the acquisition of certain property or to otherwise condemn that property after Feb. 1, 2019. In the first quarter of 2019, Boulder sent PSCo a Notice of Intent to acquire certain electric distribution assets. Boulder does not have authorization from the CPUC to initiate a condemnation proceeding at this time.

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 and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS’ retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS’ rates in those communities. The municipalities’ rate setting decisions are subject to PUCT review.

SPS is regulated by the FERC for its 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. SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Fuel, Purchased Energy and Conservation Cost-Recovery

Mechanisms —

•DCRF — Recovers distribution costs not included in rates in Texas.

•EECRF — Recovers costs for energy efficiency programs in Texas.

•EE rider — Recovers costs for energy efficiency programs in New Mexico.

•FPPCAC — Adjusts monthly to recover the actual fuel and purchased power costs in New Mexico.

•PCRf — Allows recovery of purchased power costs not included in rates in Texas.

•RPS — Recovers deferred costs for renewable energy programs in New Mexico.

•TCRF — Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in base rates in Texas.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of energy expenses. 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.

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.

Energy Sources and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements. In addition, it has evaluated water supply issues at the Tolk facility, concluding additional resource investment will be required to operate the plant through its existing life. The Ogallala aquifer has depleted more rapidly than expected. SPS installed a horizontal water well that may help delay the need for a more substantial investment solution. As a result of this issue and future environmental rules facing the plant, it sought a decrease to the remaining life of the facility in the 2017 Texas and New Mexico rate case proceedings.

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.

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including 1,000 MW ownership.

In March 2018, the NMPRC approved SPS' petition to build and own Sagamore, a 522 MW wind project in New Mexico which is expected to be placed into service in 2020. In May 2018, the PUCT approved SPS' petition to build and own Hale County, a 478 MW wind project in Texas which is expected to be placed into service in 2019. Both projects qualify for 100% of PTCs. SPS' capital investment for these wind projects is expected to be approximately \$1.6 billion.

Texas State ROFR Request for Declaratory Order — In 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility the ROFR to construct new transmission facilities located in the utility's service area. The PUCT subsequently issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities. In January 2018, SPS and two other parties filed appeals in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS has filed an additional appeal.

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NATURAL GAS UTILITY OPERATIONS

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Natural gas deliveries (Thousands of MMBtu)			
Residential	149,036	134,189	132,853
C&I	96,447	87,271	84,082
Total retail	245,483	221,460	216,935
Transportation and other	173,092	142,497	133,498
Total deliveries	418,575	363,957	350,433
Number of customers at end of period			
Residential	1,878,576	1,856,221	1,835,507
C&I	158,424	157,798	157,286
Total retail	2,037,000	2,014,019	1,992,793
Transportation and other	7,951	7,705	7,316
Total customers	2,044,951	2,021,724	2,000,109
Natural gas revenues (Millions of Dollars)			
Residential	\$1,045	\$ 1,006	\$ 930
C&I	556	524	469
Total retail	1,601	1,530	1,399
Transportation and other	138	120	132
Total natural gas revenues	\$1,739	\$ 1,650	\$ 1,531
MMBtu sales per retail customer	120.51	109.96	108.86
Revenue per retail customer	\$786	\$ 760	\$ 702
Residential revenue per MMBtu	7.01	7.50	7.00
C&I revenue per MMBtu	5.76	6.00	5.58
Transportation and other revenue per MMBtu	0.80	0.84	0.99

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily send-out (firm and interruptible) and occurrence date:

	2018		2017	
Utility Subsidiary	MMBtu	Date	MMBtu	Date
NSP-Minnesota	786,751	^(a) Jan. 12	893,062	Dec. 26
NSP-Wisconsin	159,700	Jan. 5	160,170	Dec. 26
PSCo	1,903,878	^(a) Feb. 20	1,948,167	Jan. 5

^(a) Decrease in MMBtu output due to milder winter temperatures in 2018.

Natural gas is purchased from independent suppliers, generally based on market indices that reflect current prices, and is delivered under transportation agreements with interstate pipelines.

Contracted firm deliverable pipeline capacity as of Dec. 31:

Utility Subsidiary	MMBtu
	Per Day
NSP-Minnesota	645,171
NSP-Wisconsin	140,195
PSCo	1,834,843 ^(a)

^(a) Includes 871,418 MMBtu of natural gas under third-party underground storage agreements.

The utility subsidiaries contract with providers of underground natural gas storage services. Agreements provided storage of winter natural gas and peak day firm requirements for 2018 as follows:

Utility Subsidiary	Percent of Winter Requirements	Peak Day Firm Requirements
NSP-Minnesota	24%	29%
NSP-Wisconsin	30	33

PSCo also operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas on peak days. The balance required to meet firm peak day sales obligations is primarily purchased at PSCo's city gate meter stations.

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Natural Gas Supply and Costs

Xcel Energy actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio which provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their respective state commissions.

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

	NSP-Minnesota	NSP-Wisconsin	PSCo
2018\$	4.03	\$ 3.84	\$3.20
2017\$	3.89	3.88	3.45

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. As of Dec. 31, 2018, the utility subsidiaries had the following contractual obligations:

• NSP-Minnesota — \$437 million (expire 2019 - 2033);

• NSP-Wisconsin — \$89 million (expire 2019 - 2029); and,

• PSCo — \$1.1 billion (expire 2019 - 2029).

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and NDPSC. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. The MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is also subject to the DOT, Minnesota Office of Pipeline Safety, NDPSC and SDPUC for pipeline safety compliance.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and MPSC. 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 period beginning the following January.

NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, PSCW and MPSC for pipeline safety compliance.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin to recover the actual cost of natural gas and transportation and storage services.

NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections and true-up to actual amounts on an annual basis.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction. PSCo is subject to the DOT and CPUC with regards to pipeline safety compliance.

Purchased Natural Gas and Conservation Cost-Recovery Mechanisms

• **GCA** — Recovers the costs of purchased natural gas and transportation to meet customer requirements and is revised quarterly to allow for changes in natural gas rates.

• **DSMCA** — Recovers costs of DSM and performance initiatives to achieve various energy savings goals.

• **PSIA** — Recovers costs for transmission and distribution pipeline integrity management programs.

SPS

Natural Gas Facilities Used for Electric Generation

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

GENERAL

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 milder in the winter and cooler in the summer.

See Item 7 for further information.

Competition

Xcel Energy is a vertically integrated utility subject to traditional cost-of-service regulation by state public utilities commissions. 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.

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Customers have the opportunity to supply their own power with distributed generation including, but not limited to, solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states have policies designed to promote the development of solar and other distributed energy resources through incentive policies. With these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business. The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

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.

While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with the alternatives currently available.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. Xcel Energy will likely be required to incur capital expenditures in the future to comply with requirements for remediation of MGP and other legacy sites. The scope and timing of these expenditures cannot be determined until more information is obtained regarding the need for remediation at legacy sites.

In Minnesota, Texas and Wisconsin, Xcel Energy must comply with emission budgets that require the purchase of emission allowances from other utilities. The Denver North Front Range Nonattainment Area does not meet either the 2008 or 2015 ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Gas plants which operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/or implement enhanced emissions monitoring as part of future Colorado state plans.

There are significant present and future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. Xcel Energy has 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. If future environmental regulations do not provide credit for the investments Xcel Energy has already made or if they require additional initiatives or emission reductions, substantial costs may be incurred. The EPA, as an alternative to the CPP, has proposed a new regulation that, if adopted, would require implementation of heat rate improvement projects at our coal-fired power plants. It is not known what those costs might be until a final rule is adopted and state plans are developed to implement a final regulation. Xcel Energy believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates. Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, Xcel Energy began reporting GHG emissions under the EPA's mandatory GHG Reporting Program.

Xcel Energy estimates that in 2018, it reduced the CO₂ emissions associated with the electric generating resources used to serve its customers by approximately 40% from 2005 levels. This reduction accounts for emissions from electric generating plants owned by Xcel Energy as well as purchased power.

Xcel Energy primarily relied on strategies that resulted in:

- Development of renewable energy facilities;
- Retirement and replacement of existing generating plants; and,
- Customer energy efficiency programs.

CAPITAL SPENDING AND FINANCING

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

EMPLOYEES

As of Dec. 31, 2018, Xcel Energy had 11,043 full-time employees and 49 part-time employees, of which 5,129 were covered under CBAs.

	Employees Covered by CBAs	Total Employees
NSP-Minnesota	2,064	3,278
NSP-Wisconsin	386	540
PSCo	1,904	2,426
SPS	775	1,151
XES	—	3,697
Total	5,129	11,092

Table of ContentsEXECUTIVE OFFICERS ^(a)

Name	Age (b)	Current and Recent Positions Held	Time in Position
Ben Fowke	60	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 - Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 - Present
Brett C. Carter	52	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 - Present
		Senior Vice President and Shared Services Executive, Bank of America	October 2015 - May 2018
		Senior Vice President and Chief Operating Officer, Bank of America	March 2015 - October 2015
		Senior Vice President and Chief Distribution Officer, Duke Energy Co.	February 2013 - March 2015
Christopher B. Clark	52	President and Director, NSP-Minnesota	January 2015 - Present
		Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota	October 2012 - December 2014
David L. Eves	60	Executive Vice President and Group President, Utilities, Xcel Energy Inc.	March 2018 - Present
		President and Director, PSCo	January 2015 - February 2018
		President, Director and Chief Executive Officer, PSCo	December 2009 - December 2014
Darla Figoli	56	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 - Present
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 - May 2018
		Vice President, Human Resources, Xcel Energy Inc.	February 2010 - May 2015
Robert C. Frenzel	48	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 - Present
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. ^(c)	February 2012 - April 2016
David T. Hudson	58	President and Director, SPS	January 2015 - Present
		President, Director and Chief Executive Officer, SPS	January 2014 - December 2014
Alice Jackson	40	President and Director, PSCo	May 2018 - Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 - May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	October 2011 - November 2016
Kent T. Larson	59	Executive Vice President and Group President Operations, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, Group President Operations, Xcel Energy Services Inc.	August 2014 - December 2014
		Senior Vice President Operations, Xcel Energy Services Inc.	

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Timothy O'Connor	59	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	September 2011 - August 2014
Judy M. Poferl	59	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	February 2013 - Present
		Vice President, Corporate Secretary, Xcel Energy Inc.	January 2015 - Present
Jeffrey S. Savage	47	Senior Vice President, Controller, Xcel Energy Inc.	May 2013 - December 2014
		Vice President, Controller, Xcel Energy Inc.	January 2015 - Present
Mark E. Stoering	58	President and Director, NSP-Wisconsin	September 2011 - December 2014
		President, Director and Chief Executive Officer, NSP-Wisconsin	January 2015 - Present
Scott M. Wilensky	62	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2012 - December 2014
		Senior Vice President, General Counsel, Xcel Energy Inc.	January 2015 - Present
			September 2011 - December 2014

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

(b) Ages as of Dec. 31, 2018.

(c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including TCEH the parent company of Luminant, filed a voluntary bankruptcy petition. TCEH emerged from Chapter 11 in October 2016.

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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. 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.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and each Board of Directors' committee have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors. Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and analysis occurs formally through a key risk assessment conducted by senior management, the financial disclosure process, hazard risk management procedures and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. The business planning process also identifies areas in which there is a potential for a business area to assume inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Xcel Energy has a robust compliance program and promotes a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. Xcel Energy manages and further mitigates risks through formal risk management structures, including management councils, risk committees and services of corporate areas such as internal audit, corporate controller and legal.

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 which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability.

The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Xcel Energy. The Board of Directors regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board of Directors assigns oversight of critical risks to its four committees to ensure these risks are well understood and given appropriate focus. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. Oversight of cybersecurity risks by the Operations, Nuclear, Environmental and Safety Committee includes receiving independent outside assessments of cybersecurity maturity and assessment of plans.

New risks are considered and assigned as appropriate during the annual Board of Directors' and committee evaluation process. Committee charters and annual work plans are updated accordingly. 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. Finally, 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 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 transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and outages which could cause substantial financial losses. These natural gas and electric risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial losses. We maintain insurance against some, 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.

Additionally, for natural gas costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant.

The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

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.

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

Most electric 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 when they are brought in-service 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.

The electric utility sector is undergoing a period of significant change. For example, increases in appliance, lighting and energy efficiency, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease CO₂ emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if Xcel Energy is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide and that the preference for the types of additions may change from planning to execution. In addition, we are subject to longer-term availability of the natural resource inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

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Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure. This increases the exposure to potential outdated of technologies and resultant risks. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation places downward pressure on sales growth. This may lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

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

NSP-Minnesota's two nuclear stations, PI and Monticello, subject it to the risks of nuclear generation, which include:

- Risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of radioactive materials;
- Limitations on insurance available to cover losses that might 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; and,
- Uncertainties with the technological and financial aspects of decommissioning nuclear plants. For example, assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset 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. The NRC has the authority to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

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

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota.

NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

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

If fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause 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. Low fuel costs have a positive impact on sales, however low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Significantly higher energy or fuel costs relative to sales commitments have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and could cause disruptions in our ability to provide electric and/or natural gas services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process.

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. Actual settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

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 our capital investment. Our rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our 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. In a continued low interest rate environment there has been pressure pushing down ROE. 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. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements of utility facilities and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation or tariffs may increase costs of construction and operations. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers, or these factors could cause the operating utilities to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are recoverable given the existing regulatory mechanisms in place.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

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

We cannot be assured that our current ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes 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 downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

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 markets are global and impacted by issues and events throughout the world. Capital market disruption events and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning and/or pension funds, as well as our ability to earn a return on short-term investments of excess cash.

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 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 local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or 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 incur losses.

We may at times 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, such as CAISO, SPP, PJM, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

We have additional indirect credit exposures to financial institutions in the form of 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 related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving could trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

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

Our self-insured costs of health care benefits for eligible employees have increased in recent years. 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. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

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

We are a holding company and investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow 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. Also, our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

If our 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.

Federal tax law may significantly impact our business.

Xcel Energy's utility subsidiaries collect through regulated rates estimated federal, state and local tax payments.

Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits may change the economics of resources and our resource selections. There could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize normalization may impact our ability to economically deliver certain types of resources relative to market prices.

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Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in customers and sales are correlated with economic conditions.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to additional bad debt expense.

Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal policy on trade could significantly impact the cost of materials we use. We could be at risk for higher costs for materials and our workforce. There may be delays before these additional costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, and threats of terrorism or disruptions due to 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 already 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, our 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 or an event (e.g., severe storm, severe temperature extremes, wildfires, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

A cyber 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.

Our 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 cyber security incidents, including those caused by human error.

Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing 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 could expose us to liability.

Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of 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.

Our supply chain for procurement of digital equipment may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive federal and state regulatory scrutiny. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security 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 cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems or those of our third-party service providers were to fail or be breached, we may be unable to fulfill critical business functions. We are unable to quantify the potential impact of cyber security incidents on our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring may not be effective given the constant changes to threat vulnerability.

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.

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

We rely on third party contractors to perform work for operations, maintenance and construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance.

Cyber security breaches have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

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Public 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 and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system.

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

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. All of the steps that Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies. While those actions likely would have put Xcel Energy in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

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.

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. The FERC can impose penalties of up to \$1.3 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. Additionally, the PHMSA, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

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, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities.

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 (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

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 the O&M costs incurred to comply with the requirements.

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.

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 may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require system backup, costs, 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.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities. While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Item 1B — Unresolved Staff Comments

None.

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Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, SPS and PSCo is subject to the lien of their first mortgage bond indentures.

Electric Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW (a)
Steam:			
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511
Sherco-Becker, MN			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 (b)
Monticello, MN, 1 Unit	Nuclear	1971	617
PI-Welch, MN			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units	Wood/Refuse	Various	36 (c)
Combustion Turbine:			
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2002	494 (d)
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Various locations, 14 Units	Natural Gas	Various	67
Wind:			
Border-Rolette County, ND, 75 Units	Wind	2015	148 (e)
Courtenay Wind, ND, 100 Units	Wind	2016	195 (e)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	101 (e)
Nobles-Nobles County, MN., 134 Units	Wind	2010	200 (e)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 (e)
		Total	7,530

(a) Summer 2018 net dependable capacity.

(b) Based on NSP-Minnesota's ownership of 59%.

(c) Refuse-derived fuel is made from municipal solid waste.

(d) Black Dog Unit 6 was commissioned and placed into operation in the third quarter of 2018.

(e) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	MW (a)
Steam:			
Bay Front-Ashland, WI, 3 Units	Coal/Wood/Natural Gas	1948 - 1956	56
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16 (b)
Combustion Turbine:			
French Island-La Crosse, WI, 2 Units	Oil	1974	122
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/Oil	1973	234
Hydro:			

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Various locations, 63 Units	Hydro	Various	135
		Total	563

(a) Summer 2018 net dependable capacity.

(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	MW (a)
Steam:			
Comanche-Pueblo, CO (b)			
Unit 1	Coal	1973	325
Unit 2	Coal	1975	335
Unit 3	Coal	2010	500 (c)
Craig-Craig, CO, 2 Units (d)	Coal	1979 - 1980	82 (e)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233 (f)
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	968
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580
Various locations, 6 Units	Natural Gas	Various	171
Hydro:			
Cabin Creek-Georgetown, CO			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 9 Units	Hydro	Various	26
Wind:			
Rush Creek, CO, 300 units	Wind	2018	600 (g)
		Total	5,685

(a) Summer 2018 net dependable capacity.

(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.

(c) Based on PSCo's ownership of 67%.

(d) Craig Unit 1 is expected to be retired early in 2025.

(e) Based on PSCo's ownership of 10%.

(f) Based on PSCo's ownership of 75% of Unit 1 and 37% of Unit 2.

Generation capability is based on the maximum output level of wind units, including the Rush Creek Wind Project.

(g) Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit	Fuel	Installed	MW (a)
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	251
Harrington-Amarillo, TX, 3 Units	Coal	1976 - 1980	1,018
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, 4 Units	Natural Gas	1952 - 1964	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			

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Cunningham-Hobbs, NM, 2 Units	Natural Gas	1998	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, TX, 1 Unit	Natural Gas	1963 - 1976	61
	Total		4,406

(a) Summer 2018 net dependable capacity.

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Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2018:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	13,560	3,415	4,062	9,028
230 KV	2,202	—	12,053	9,675
161 KV	615	1,823	—	—
138 KV	—	—	91	—
115 KV	7,372	1,817	5,051	14,493
Less than 115 KV	86,185	32,831	78,446	25,820

Electric utility transmission and distribution substations at Dec. 31, 2018:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	348	203	232	459

Natural gas utility mains at Dec. 31, 2018:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	90	3	2,080	20	11
Distribution	10,437	2,466	22,518	—	—

Item 3 — Legal Proceedings

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

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 was listed on the New York Stock Exchange (NYSE) in 2017, but moved to the Nasdaq Global Select Market (Nasdaq) in 2018. The trading symbol is XEL. The number of common stockholders of record as of Dec. 31, 2018 was approximately 57,059.

See Item 7 for further information.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five years (assuming a \$100 investment on Dec. 31, 2013, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 42 companies at year-end and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*

Xcel Energy Inc., the EEI Investor-Owned Electrics and the Standard & Poor's 500

*\$100 invested on Dec. 31, 2013 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

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Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2018 Annual Meeting of Shareholders, which is incorporated by reference.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2018, 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 — Selected Financial Data

Selected financial data for Xcel Energy related to the five most recent years ended Dec. 31.

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2018	2017	2016	2015	2014
Operating revenues	\$11,537	\$11,404	\$11,107	\$11,024	\$11,686
Operating expenses ^(a)	9,572	9,181	8,867	9,024	9,738
Net income	1,261	1,148	1,123	984	1,021
Earnings available to common shareholders	1,261	1,148	1,123	984	1,021
Diluted earnings per common share	2.47	2.25	2.21	1.94	2.03
Financial information					
Dividends declared per common share	1.52	1.44	1.36	1.28	1.20
Total assets ^{(b) (c)}	45,987	43,030	41,155	38,821	36,958
Long-term debt ^{(c) (d)}	15,803	14,520	14,195	12,399	11,500

As a result of adopting ASU No. 2017-07 (Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715), \$33 million and \$26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated statements of income for the years ended Dec. 31, 2017 and Dec. 31, 2016, respectively.

As a result of adopting ASU No. 2015-17 (Balance Sheet Classification of Deferred Taxes, Topic 740), \$140 million of current deferred income taxes was retrospectively reclassified to long-term deferred income tax liabilities on the consolidated balance sheet as of Dec. 31, 2015.

As a result of adopting ASU No. 2015-03 (Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30), \$92 million of deferred debt issuance costs was retrospectively reclassified from other non-current assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

^(d) Includes capital lease obligations.

Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations include the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. The utility subsidiaries serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the utility subsidiaries, the TransCo 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.

Xcel Energy Inc.'s immaterial nonregulated subsidiaries are Eloigne and Capital Services.

Management's Strategic Priorities

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need. We strive to provide our investors an attractive value proposition and our customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep bills low.

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver a competitive total return for our shareholders.

Lead the clean energy transition

For more than a decade, we have managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently reduces carbon emissions and transitions our operations for the future. As a result, we have successfully reduced our carbon emissions to our customers by approximately 40% from 2005 to 2018. We expect to reduce our carbon footprint by 80% by 2030 (over 2005 levels). We have also announced our vision to serve all customers with 100% zero-carbon emissions by 2050.

Our service territories benefit from the geographic concentration of favorable renewable resources. Strong wind and high solar irradiance yield high generation capacity factors, which lowers the cost of these resources. The combination of high capacity factors, grid options from transmission investment and market operations, improved supply chain, technological improvements and the extension of the renewable tax credits translates into low renewable energy costs for our customers. As a result, we are able to invest in renewable generation, in which the capital costs are largely or completely offset by fuel savings. This provides us the opportunity to lower the emission profile of our generation fleet, grow our renewable portfolio and provide significant fuel savings to our customers. We call this our “Steel for Fuel” strategy.

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We are transitioning how we produce, deliver and encourage the efficient use of energy through four primary mechanisms:

- Increasing the use of affordable renewable energy;
- Offering energy efficiency programs for customers;
- Retiring or repowering coal units and modernizing our generating plants; and,
- Advancing power grid capabilities.

We have announced ambitious plans to add approximately 3,600 MW of wind energy on our system by 2021.

In addition, the proposed CEP in Colorado encompasses the retirement of 660 MW from two coal-fired units at Comanche and the addition of up to 1,100 MW of wind, 700 MW of solar and 275 MW of battery storage.

Enhance the customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price. We will continue to expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs. We are also in the process of transforming our transmission and distribution systems to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security and keeping customer bills affordable. We also are expanding our Renewable*Connect program, which allows customers to choose how much of their energy comes from renewable sources. Renewable*Connect has regulatory approval in Minnesota, Colorado and Wisconsin. This is yet another way for us to add renewable energy and meet the needs of our customers. Importantly, Renewable*Connect does not negatively impact the bills of non-participants. Finally, we are improving our communications to enable customers to interact with us in the way they prefer.

Keep bills low

Xcel Energy is very focused on our customers and the impact our actions have on their bill. Our objective is to keep total bill increases at or below the rate of inflation so our prices remain competitive relative to alternatives. We expect to continue to keep our customer bills low by executing on our Steel for Fuel plan, controlling O&M costs and promoting energy efficiency and conservation.

Xcel Energy is working to keep long-term O&M expense relatively consistent without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow. In 2018, we experienced warmer than normal summer weather, which caused us to spend additional O&M for vegetation management and system maintenance due to the hot summer, business systems costs, investments to improve and enhance business processes and customer service, as well as damage prevention and remediation costs. However, we remain committed to our long-term objective of improving operating efficiencies and taking costs out of the business for the benefit of our customers and anticipate that our long-term O&M expense trend will remain relatively consistent.

Provide a competitive total return to investors and maintain strong investment grade credit rating

Through our disciplined approach to business growth, financial investment, operations and safety, we plan to:

- Deliver long-term annual EPS growth of 5% to 7%;
- Deliver annual dividend increases of 5% to 7%;
- Target a dividend payout ratio of 60% to 70% of annual ongoing EPS; and,
- Maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range.

We have consistently achieved our financial objectives, meeting or exceeding our earnings guidance range for fourteen consecutive years, and we believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 6.1% and our dividend has grown approximately 4.5% annually from 2005 - 2018. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range, while our secured operating company debt ratings are in the A range.

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 the ongoing return on equity (ROE), electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP. Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

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

Electric and Natural Gas Margins

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

Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

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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. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the year ended Dec. 31, 2017, Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately \$23 million for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. For the year ended Dec. 31, 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

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

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

	2018 GAAP and Ongoing Diluted EPS	2017 GAAP Diluted EPS	Impact of TCJA (a)	Ongoing Diluted EPS	2016 GAAP and Ongoing Diluted EPS
Diluted Earnings (Loss) Per Share					
PSCo	\$ 1.08	\$0.97	\$(0.03)	\$ 0.94	\$ 0.91
NSP-Minnesota	0.96	0.96	0.05	1.01	0.96
SPS	0.42	0.31	(0.01)	0.30	0.30
NSP-Wisconsin	0.19	0.16	—	0.16	0.14
Equity earnings of unconsolidated subsidiaries (a)	0.04	0.07	(0.04)	0.03	0.05
Regulated utility (b)	2.69	2.47	(0.03)	2.45	2.35
Xcel Energy Inc. and other	(0.22)	(0.22)	0.07	(0.15)	(0.15)
Total (b)	\$ 2.47	\$ 2.25	\$ 0.05	\$ 2.30	\$ 2.21

(a) Includes income taxes.

(b) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company 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.

Earnings Adjusted for Certain Items

2018 Comparison with 2017

2017 Adjustment to GAAP Earnings — Impact of the TCJA — Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately \$23 million in the fourth quarter of 2017 for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. The income tax expense associated with the TCJA enactment has been excluded from Xcel Energy's 2017 ongoing earnings, given the non-recurring nature of the TCJA's broad and sweeping reform of the IRC.

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

Differences between GAAP and ongoing earnings are due to the non-recurring impact of the TCJA experienced in 2017. Explanations for operating company results below exclude the offsetting impacts of the TCJA on sales, depreciation and amortization expense and income tax.

Xcel Energy — GAAP and ongoing earnings increased \$0.22 and \$0.17 per share, respectively. Earnings increased as a result of higher electric and natural gas revenues primarily due to favorable weather and sales growth and higher AFUDC. These positive factors were partially offset by increased O&M, depreciation and interest expenses. GAAP earnings for 2017 include the non-recurring negative impact of the TCJA.

PSCo — GAAP and ongoing 2018 earnings increased \$0.11 and \$0.14 per share, respectively. Increases were driven by higher natural gas margins largely due to a natural gas rate increase, higher electric margins reflecting favorable weather and sales growth, and additional AFUDC associated with the Rush Creek wind project. These items were partially offset by higher O&M expenses, interest charges, depreciation expense and property taxes.

NSP-Minnesota — 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased \$0.05 per share. The decrease in ongoing earnings reflects higher depreciation expense and O&M expenses. These amounts were partially offset by higher electric and natural gas margins attributable to favorable weather.

SPS — 2018 GAAP and ongoing earnings increased \$0.11 and \$0.12 per share, respectively. Increases were primarily due to higher electric margins reflecting favorable weather and sales growth and a rate increase in New Mexico, AFUDC related to the Hale County wind project and lower interest charges. Increases were partially offset by higher depreciation expense.

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NSP-Wisconsin — 2018 GAAP and ongoing earnings increased \$0.03 per share. Increases reflect higher electric and natural gas rates and the impact of favorable weather and sales growth, which were partially offset by higher depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other primarily includes financing costs at the holding company. 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased \$0.07 per share. Decrease was primarily due to higher interest expense related to additional debt and the change in the federal income tax rate. 2017 Comparison with 2016

Xcel Energy — GAAP earnings increased \$0.04 per share for 2017. Ongoing earnings increased \$0.09 per share, excluding the impact of the TCJA. Earnings were higher as a result of increased electric and natural gas margins to recover infrastructure investments, reduced O&M expenses, a lower ETR and higher AFUDC. These positive factors were partially offset by increased depreciation expense, interest charges and property taxes.

PSCo — GAAP earnings increased \$0.06 per share for 2017. Ongoing earnings increased \$0.03 per share, excluding the impact of the TCJA. The increase in earnings was driven by higher electric and natural gas margins, increased AFUDC primarily related to the Rush Creek wind project, a decrease in O&M expenses (timing of generation outages) and a lower ETR, partially offset by higher depreciation expense, interest charges and the impact of unfavorable weather.

NSP-Minnesota — GAAP earnings were flat for 2017. Ongoing earnings increased \$0.05 per share, excluding the impact of the TCJA. The change reflects higher electric margins driven by a 2017 Minnesota rate increase as well as increased gas margins, a lower ETR and reduced O&M expenses. These positive factors were partially offset by higher depreciation expense due to increased invested capital as well as prior year amortization of Minnesota's excess depreciation reserve and higher property taxes.

SPS — GAAP earnings increased \$0.01 per share for 2017. Ongoing earnings were flat, excluding the impact of the TCJA. Rate increases in Texas and New Mexico and a lower ETR were offset by higher depreciation expense (representing continued investment), O&M expenses (including the prior year deferrals associated with the Texas 2016 rate case), property taxes and the impact of unfavorable weather.

NSP-Wisconsin — GAAP and ongoing earnings increased \$0.02 per share for 2017. The change in ongoing earnings was driven by a rise in electric and natural gas rates, partially offset by additional depreciation expense related to continued transmission and distribution investments and higher O&M expenses.

Equity earnings of unconsolidated subsidiaries — GAAP earnings increased \$0.02 per share for 2017. Ongoing earnings of unconsolidated subsidiaries decreased \$0.02 per share, excluding the impact of the TCJA. The decline primarily related to lower revenues due to lower rates at WYCO.

Changes in Diluted EPS

Components significantly contributing to changes in 2018 EPS compared with the same period in 2017 and 2017 EPS compared to 2016:

2018 vs. 2017

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP diluted EPS — 2017	\$2.25
Impact of the TCJA ^(a)	0.05
Ongoing diluted EPS — 2017	\$2.30
Components of change — 2018 vs. 2017	
Higher electric margins (excluding TCJA impacts) ^(a)	0.31
Higher natural gas margins (excluding TCJA impacts) ^(a)	0.13
Higher AFUDC — equity	0.07
Higher O&M expenses	(0.10)
Higher depreciation and amortization (excluding TCJA impacts) ^(a)	(0.10)

Higher ETR (excluding TCJA impacts) ^(a)	(0.07)
Higher interest charges	(0.04)
Higher conservation and demand side management (DSM) program expenses (offset by higher revenues)	(0.02)
Higher taxes (other than income taxes)	(0.01)
GAAP and ongoing diluted EPS — 2018	\$2.47

Estimated net impact of the TCJA, including assumptions regarding future regulatory proceedings: ^(a)	
Income tax — rate change and ARAM (net of deferral)	0.68
Electric margin reductions (net)	(0.46)
Natural gas margin reductions (net)	(0.06)
Depreciation and amortization reductions (Colorado prepaid pension)	(0.11)
Holding company — interest expense	(0.04)
Total	\$0.01
2017 vs. 2016	

Diluted Earnings (Loss) Per Share	Dec.
	31
GAAP and ongoing diluted EPS — 2016	\$2.21

Components of change — 2017 vs. 2016	
Higher electric margins ^(a)	0.16
Lower ETR ^(b)	0.07
Higher natural gas margins	0.03
Higher AFUDC — equity	0.03
Lower O&M expenses	0.03
Higher depreciation and amortization	(0.21)
Higher conservation and DSM program expenses ^(c)	(0.03)
Higher interest charges	(0.02)
Higher taxes (other than income taxes)	(0.02)
Equity earnings of unconsolidated subsidiaries	(0.02)
Other, net	0.02
GAAP diluted EPS — 2017	\$2.25
Impact of the TCJA	0.05
Ongoing diluted EPS — 2017	\$2.30

^(a) Includes an increase of \$23 million in revenues from conservation and DSM programs, offset by related expenses, for the twelve months ended Dec. 31, 2017.

ETR includes the impact of an additional \$20 million of wind PTCs for the twelve months ended Dec. 31, 2017, ^(b) which are largely flowed back to customers through electric margin, as well as the impact of the TCJA recorded in the fourth quarter of 2017.

^(c) Offset by higher revenues.

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ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

ROE	2018		2017		Impact of the TCJA	Ongoing	
	GAAP and Ongoing ROE	%	GAAP ROE	%		ROE	%
PSCo	9.10	%	8.90	%	(0.24)%	8.66	%
NSP-Minnesota	8.91		9.05		0.45	9.50	
SPS	9.14		7.84		(0.30)	7.54	
NSP-Wisconsin	10.77		9.41		0.09	9.50	
Operating Companies	9.14		8.84		0.03	8.87	
Xcel Energy	10.65		10.21		0.21	10.42	

Reconciliation of GAAP earnings (net income) to ongoing earnings and GAAP diluted EPS to ongoing diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
GAAP earnings	\$1,261	\$1,148	\$1,123
Estimated impact of TCJA	—	23	—
Ongoing earnings	\$1,261	\$1,171	\$1,123
Diluted EPS	2018	2017	2016
GAAP diluted EPS	\$2.47	\$2.25	\$2.21
Estimated impact of TCJA	—	0.05	—
Ongoing diluted EPS	\$2.47	\$2.30	\$2.21

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 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 and the amount of natural gas or electricity historically used per degree of temperature. Weather deviations from normal levels can affect Xcel Energy's financial performance.

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 20-year 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:

	2018	2017 vs.	2018	2016 vs.	2017
	vs.	Normal	vs.	Normal	vs.
	Normal		2017		2016
HDD	2.2 %	(10.0)%	12.2 %	(13.4)%	2.6 %
CDD	26.7	6.5	20.5	11.1	(3.5)

THI 37.3 (11.3) 56.9 7.7 (18.5)

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

	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 2016
Retail electric	\$0.114	\$(0.036)	\$0.150	\$0.004	\$(0.040)
Firm natural gas	0.007	(0.023)	0.030	(0.025)	0.002
Total (excluding decoupling)	\$0.121	\$(0.059)	\$0.180	\$(0.021)	\$(0.038)
Decoupling — Minnesota electric	(0.051)	0.022	(0.073)	(0.002)	0.024
Total (adjusted for recovery from decoupling)	\$0.070	\$(0.037)	\$0.107	\$(0.023)	\$(0.014)

Sales Growth (Decline) — Sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	2018 vs. 2017					
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy	
Actual						
Electric residential	3.6%	5.8	%	8.6	%	5.4
Electric C&I	1.5	1.1		5.4		3.2
Total retail electric sales	2.2	2.5		5.9		3.9
Firm natural gas sales	9.3	14.6		N/A		13.1

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2018 vs. 2017

	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.8%	(0.5)%	2.0 %	0.2 %	0.8 %
Electric C&I	1.2	(0.4)	4.6	2.3	1.5
Total retail electric sales	1.3	(0.4)	4.1	1.7	1.3
Firm natural gas sales	2.2	2.7	N/A	3.1	2.4

Weather-normalized 2018 Electric Sales Growth (Decline)

PSCo — Higher residential sales growth reflects customer additions and slightly higher use per customer. C&I growth was due to an increase in customers and higher use per customer, predominately from the fabricated metal, food products, metal mining and oil and gas extraction industries.

NSP-Minnesota — Residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was due to an increase in customers offset by lower use per customer. Increased sales to large customers in manufacturing and energy were offset by declines in services.

SPS — Residential sales grew largely due to higher use per customer and customer additions. The increase in C&I sales was driven by the oil and natural gas industry in the Permian Basin.

NSP-Wisconsin — Sales growth was primarily attributable to customer additions, partially offset by lower use per customer. C&I growth was largely due to higher use per large customer, customer additions and increased sales to sand mining and energy industries.

Weather-normalized 2018 Natural Gas Sales Growth

Higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

2017 vs. 2016

	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(1.8)%	(2.1)%	(3.5)%	(0.8)%	(2.1)%
Electric C&I	(0.1)	(1.4)	1.3	2.2	(0.1)
Total retail electric sales	(0.6)	(1.6)	0.2	1.3	(0.7)
Firm natural gas sales	(2.2)	9.3	N/A	11.3	2.1

2017 vs. 2016

	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(1.6)%	(0.7)%	(1.2)%	0.3 %	(1.0)%
Electric C&I	0.1	(1.0)	1.5	2.5	0.2
Total retail electric sales	(0.4)	(1.0)	0.9	1.8	(0.2)
Firm natural gas sales	0.6	4.7	N/A	5.7	2.2

2017 vs. 2016 (Excluding Leap Day) ^(b)

	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential ^(a)	(1.3)%	(0.5)%	(1.0)%	0.6 %	(0.8)%
Electric C&I	0.3	(0.8)	1.8	2.7	0.4
Total retail electric sales	(0.2)	(0.7)	1.1	2.1	0.1
Firm natural gas sales	1.1	5.2	N/A	6.3	2.7

^(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth (decline) estimates.

Estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation.

- (b) Estimated impact of the additional day of sales in 2016 was approximately 0.3% for retail electric and 0.5% for firm natural gas for the twelve months ended.

Weather-normalized 2017 Electric Sales Growth (Decline) (Excluding Leap Day)

PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, partially offset by lower use for the small C&I class.

NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services more than offset increased sales to large customers in manufacturing and energy industries.

SPS' residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use for large C&I customers driven by the oil and natural gas industry in the Permian Basin.

NSP-Wisconsin's residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and increased sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized 2017 Natural Gas Sales Growth

Higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

Weather-normalized sales for 2019 are projected to be relatively consistent with 2018 levels for retail electric customers and within a range of 0.0% to 1.0% over 2018 levels for retail natural gas customers.

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Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. Electric margin was reduced by approximately \$105 million in 2018 and \$130 million in 2017 for PTCs (grossed up for federal income tax) which were returned to customers. Margin reductions for PTCs are largely offset by income tax benefits.

Electric revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Electric revenues before TCJA impact	\$10,046	\$9,676	\$9,500
Electric fuel and purchased power before TCJA impact	(3,867)	(3,757)	(3,718)
Electric margin before TCJA impact	\$6,179	\$5,919	\$5,782
TCJA impact (offset as a reduction in income tax)	(314)	—	—
Electric margin	\$5,865	\$5,919	\$5,782
Electric Margin			

	2018
(Millions of Dollars)	vs.
	2017
Estimated impact of weather (net of Minnesota decoupling)	\$63
Retail sales growth (net of Minnesota decoupling and sales true-up)	52
Non-fuel riders	45
Purchased capacity costs	38
Wholesale transmission revenue (net)	31
Retail rate increase (Wisconsin, New Mexico and Michigan)	20
Other (net)	11
Total increase in electric margin before TCJA impact	\$260
TCJA impact (offset as a reduction in income tax)	(314)
Total decrease in electric margin	\$(54)

	2017
(Millions of Dollars)	vs.
	2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	\$123
Non-fuel riders	33
Conservation and DSM revenues (offset by expenses)	23
Decoupling (weather portion — Minnesota)	18
Purchased capacity costs	8
Wholesale transmission revenue (net of costs)	(38)
Estimated impact of weather	(30)
Conservation incentive	(18)
Other (net)	18
Total increase in electric margin	\$137

Natural Gas Margin

Total natural gas expense varies with changing sales requirements and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms.

Natural gas revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Natural gas revenues before TCJA impact	\$1,778	\$1,650	\$1,531
Cost of natural gas sold and transported	(843)	(823)	(733)
Natural gas margin before TCJA impact	\$935	\$827	\$798

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TCJA impact (offset as a reduction in income tax)	(39)	—	—
Natural gas margin	\$896	\$827	\$798
Natural Gas Margin			

(Millions of Dollars) 2018
vs.

2017

Retail rate increase (Colorado, Wisconsin and Michigan) \$58

Estimated impact of weather 24

Infrastructure and integrity riders 13

Sales growth 6

Conservation revenue (offset by expenses) 3

Other (net) 4

Total increase in natural gas margin before TCJA impact \$108

TCJA impact (offset as a reduction in income tax) (39)

Total increase in natural gas margin \$69

2017

(Millions of Dollars) vs.

2016

Infrastructure and integrity riders \$ 18

Retail sales growth, excluding weather impact 7

Estimated impact of weather 1

Other (net) 3

Total increase in natural gas margin \$ 29

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased \$82 million, or 3.6%, for 2018. Significant changes are summarized below:

2018
(Millions of Dollars) vs.

2017

Business systems and contract labor \$ 39

Distribution costs 19

Natural gas systems damage prevention and other remediation 12

Generation plant costs (including increased wind O&M) 11

Nuclear plant operations and amortization (9)

Other (net) 10

Total increase in O&M expenses \$ 82

Business systems and contract labor costs increased due to growing network and storage needs, cybersecurity, initiatives to support our customer strategy, and initiatives to improve business processes;

Distribution costs reflect higher maintenance expenses, including vegetation management; and,

Nuclear plant operations and amortization are lower largely reflecting savings initiatives and reduced refueling outage costs.

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O&M expenses decreased \$23 million, or 1.0%, for 2017. Significant changes are summarized as follows:

	2017
(Millions of Dollars)	vs.
	2016
Nuclear plant operations and amortization	\$(27)
Plant generation costs	(23)
Transmission costs	(2)
Employee benefits expense	17
Texas 2016 electric rate case cost deferral	16
Electric distribution costs	2
Other (net)	(6)
Total decrease in O&M expenses	\$(23)

• Nuclear plant operations and amortization expenses are lower mostly due to reduced refueling outage costs and operating efficiencies.

• Plant generation costs decreased as a result of lower expenses associated with planned outages and overhauls at a number of generation facilities.

• Employee benefits expense includes the recognition of an \$8 million pension settlement expense in the fourth quarter of 2017.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased \$17 million, or 6.2%, for 2018. The increase was primarily due to recovery for conservation programs to assist customers in reducing energy use. Conservation and DSM expenses are generally recovered concurrently through riders and base rates. Timing of recovery may vary from when costs are incurred.

Conservation and DSM program expenses increased \$28 million, or 11.4%, for 2017 compared with 2016. The increase was due to higher customer participation in electric conservation programs and recovery rates, mostly in Minnesota.

Depreciation and Amortization — Depreciation and amortization increased \$163 million, or 11%, for 2018. The increase was primarily driven by capital investments and additional amortization of a prepaid pension asset in Colorado (approximately \$75 million) related to TCJA settlements, which were offset by lower income taxes.

Depreciation and amortization increased \$176 million, or 13.5%, for 2017 compared with 2016. The increase was primarily due to capital investments and prior year amortization of the excess depreciation reserve in Minnesota.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased \$11 million, or 2.0%, for 2018. The increase was primarily due to higher property taxes.

Taxes (other than income taxes) increased \$13 million, or 2.4%, for 2017 compared with 2016. The increase was primarily due to higher property taxes in Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC increased \$46 million for 2018. The increase was primarily due to the Rush Creek and Hale wind projects and other capital investments.

AFUDC increased \$23 million for 2017 compared with 2016. The increase was primarily due to higher CWIP, particularly the Rush Creek wind project.

Interest Charges — Interest expense increased \$37 million, or 5.6%, for 2018. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Interest charges increased \$16 million, or 2.5%, for 2017 compared with 2016. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased \$361 million for 2018. The decrease was primarily driven by a lower federal tax rate due to the TCJA, lower pretax earnings, a one time, non-cash income tax expense related to the TCJA in 2017, an increase in plant-related regulatory differences related to ARAM (net of deferrals), 2018 non-plant excess accumulated deferred income tax amortization, and the impact of 2018 investment tax credits. These were partially offset by a higher tax benefit for the resolution of past appeals/audits in 2017 and a higher tax benefit for adjustments in 2017. The ETR was 12.6% for 2018 compared with 32.1% for 2017. The lower ETR in 2018 was largely due to the

adjustments above.

Income tax expense decreased \$39 million for 2017 compared with 2016. The decrease was primarily driven by increased wind PTCs, a net tax benefit related to the resolution of appeals/audits in 2017, an increase in R&E credits, lower pretax earnings in 2017 and a rise in permanent plant-related adjustments. PTCs are flowed back to customers and reduce electric margin. The decrease was partially offset by the estimated one-time, non-cash, income tax expense recognized in the fourth quarter related to the TCJA. The ETR was 32.1% for 2017 compared with 34.1% for 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above. Excluding the impact for the TCJA adjustment, the ETR would have been 30.7% for 2017.

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

Xcel Energy Inc. and Other Results

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

	Contribution (Millions of Dollars)		
	2018	2017	2016
Xcel Energy Inc. financing costs	\$(110)	\$(79)	\$(71)
Eloigne ^(a)	—	2	1
Xcel Energy Inc. taxes and other results	(5)	(35)	(6)
Total Xcel Energy Inc. and other costs	\$(115)	\$(112)	\$(76)

	Contribution (Diluted Earnings (Loss) Per Share)		
	2018	2017	2016
Xcel Energy Inc. financing costs	\$(0.21)	\$(0.15)	\$(0.14)
Eloigne ^(a)	—	—	—
Xcel Energy Inc. taxes and other results	(0.01)	(0.07)	(0.01)
Total Xcel Energy Inc. and other costs	\$(0.22)	\$(0.22)	\$(0.15)

^(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

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

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. Historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

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Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and WGI. The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries and WGI are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy Inc.'s utility subsidiaries request changes in rates for utility services through filings with governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate case filings 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.

Tax Reform — Regulatory Proceedings

In December 2017, the TCJA was signed into law, enacting significant changes to the IRC, including a reduction of the corporate income tax rate from 35% to 21% and a resulting reduction in deferred tax assets and liabilities. As a result of IRS requirements and past regulatory treatment of income taxes in the determination of regulated rates, the impacts of TCJA are primarily recognized as a regulatory liability. Treatment of these tax benefits, (e.g., degree to which benefits will be used to refund currently effective rates and/or used to mitigate other costs and potential future rate increases) is subject to regulatory approval.

Concluded and ongoing regulatory TCJA proceedings:

Operating Company	Utility Service	Approval Date	Additional Information
NSP-Minnesota	Electric and Natural Gas	August 2018	Minnesota — In 2018, the MPUC ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including \$135 million to electric customers and low income program funding, and \$6 million to natural gas customers.
NSP-Minnesota	Electric	July 2018	South Dakota — In July 2018, the SDPUC approved a settlement providing a one-time customer refund of \$11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Minnesota	Natural Gas	November 2018	North Dakota — In November 2018, the NDPSC approved a TCJA settlement in which NSP-Minnesota will amortize \$1 million annually of the regulatory asset for the remediation of the MGP site in Fargo, ND and retain the TCJA savings to offset the MGP amortization expense.
NSP-Minnesota	Electric	February 2019	North Dakota — In February 2019, the NDPSC approved a settlement including a one-time customer refund of \$10 million for 2018, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Wisconsin	Electric and Natural Gas	May 2018	Wisconsin — In May 2018, the PSCW approved customer refunds of \$27 million and deferrals of approximately \$5 million until NSP-Wisconsin's next rate case proceeding.
NSP-Wisconsin	Electric and Natural Gas	May 2018	Michigan — In May 2018, the MPSC approved electric and natural gas TCJA settlement agreements. Most of the electric TCJA benefits were reflected in NSP-Wisconsin's approved Michigan 2018 electric base rate case.
PSCo	Natural Gas	December 2018	In February 2018, the ALJ recommended approval of a TCJA settlement agreement, which included a \$20 million reduction to PSCo's provisional rates effective March 1, 2018. In September 2018, PSCo revised its 2018 TCJA benefit estimate to \$24 million and requested an equity ratio of 56% to offset

			the negative impact of the TCJA on credit metrics. In December 2018, the CPUC approved an equity ratio of 54.6% and utilized the remainder of the TCJA benefit to reduce an existing prepaid pension asset. The CPUC also ordered 2018 excess non-plant ADIT benefits of \$11.1 million be utilized to accelerate amortization of the prepaid pension asset.
PSCo	Electric	June 2018 October 2018	In 2018, the CPUC approved a TCJA settlement agreement that included a customer refund of \$42 million in 2018, with the remainder of the \$59 million of TCJA benefits to be used to accelerate the amortization of an existing prepaid pension asset. For 2019, the expected customer refund is estimated to be \$67 million, and amortization of the prepaid pension asset is estimated to be \$34 million. Impacts of the TCJA for 2020 and future years are expected to be addressed in a future electric rate case. Texas - In December 2018, the PUCT approved a rate settlement which fully reflects the TCJA cost impacts and results in no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57% equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.
SPS	Electric	December 2018	New Mexico - In September 2018, the NMPRC issued its final order in SPS' 2017 electric rate case, which included a \$10 million refund of the 2018 impact of the TCJA. SPS subsequently filed an appeal with the NMSC, including the order to refund retroactive TCJA savings. The NMSC granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs.
SPS	Electric	Pending	On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 and eliminate the retroactive TCJA refund. The revised order would be subject to further administrative or judicial review.

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

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Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
NSP-Minnesota (MPUC)					
TCR	Electric	\$98	November 2017	Pending	Reflects the revenue requirements for 2018 and a true-up for 2017 and is based on a proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
CIP Incentive	Electric & Natural Gas	\$34	March 2018	Received	The MPUC approved 2017 CIP electric and natural gas financial incentives, effective October 2018, of \$30 million and \$4 million, respectively.
CIP Rider	Electric & Natural Gas	\$57	March 2018	Received	The MPUC approved the forecasted 2018 electric and natural gas CIP riders with estimated 2019 recovery of \$48 million and \$9 million of electric and natural gas CIP expenses, respectively.
2018 GUIC	Natural Gas	\$23	November 2017	Pending	Proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
2019 GUIC	Natural Gas	\$29	November 2018	Pending	Proposed ROE of 10.25%. Timing of the MPUC decision is uncertain.
RDF	Electric	\$42	October 2018	Received	The MPUC approved the 2019 RDF rate based on a net revenue requirement of \$42 million, effective January 2019.
RES	Electric	\$23	November 2017	Pending	Reflects the revenue requirements for 2018, 2017 true-up and a proposed ROE of 10%. The MPUC decision is expected in the first quarter of 2019.
PSCo (CPUC)					
Multi-Year Rate Case	Natural Gas	\$139	June 2017	Received	Proposed annual revenue request of \$139 million over three years, \$63 million for 2018. Requested an ROE of 10.0% and an equity ratio of 55.25%. In August 2018, CPUC approved an increase of \$46 million (prior to TCJA impacts). The interim decision included application of a 2016 HTY, a 13-month average rate base, an ROE of 9.35%, an equity ratio of 54.6% and provided no return on the prepaid pension asset. In December 2018, the CPUC issued the final ruling which upheld the interim decision and finalized the TCJA impacts.
DSM Incentive	Electric & Natural Gas	\$11	April 2018	Received	In October 2018, the CPUC approved a settlement to extend the PSIA rider through 2021.
SPS (PUCT) Rate Case	Electric	\$54		Received	PSCo earned an electric and natural gas DSM incentive of \$9 million and \$2 million, respectively, for achieving its 2017 savings goals.

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In 2017, SPS filed a retail electric, non-fuel base rate increase case in Texas, which included an ROE of 9.5%. In December 2018, PUCT issued a final order approving a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt.

In November 2018, SPS filed an application with the PUCT requesting permission to recover \$5.4 million in unbilled TCRF revenue from January 23, 2018 through June 9, 2018. Timing of a final order on this matter is uncertain.

SPS (NMPRC)

Rate Case	Electric	\$41	November 2016	Pending
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In 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision is not expected until the second half of 2019.

In September 2018, the NMPRC approved a revenue increase of approximately \$8 million, effective Sept. 27, 2018, based on a ROE of 9.1% and a 51% equity ratio. The NMPRC also ordered a refund of \$10 million associated with the TCJA impacts (retroactive Jan. 1, 2018 - Sept. 27, 2018). SPS recorded a regulatory liability for this amount in the third quarter of 2018. SPS subsequently filed an appeal of the order. The NMSC subsequently granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs.

Rate Case	Electric	\$43	October 2017	Received/Pending
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On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 with the following: eliminating the retroactive refund associated with the TCJA, approving a ROE of 9.56% and approving an equity ratio of 53.97%. Annual revenue increase based on terms of the settlement agreement would be \$12.5 million (\$8 million from original order plus \$4.5 million for changes in ROE and equity ratio). New rates would be effective as of the date provided by the revised NMPRC order (not retrospective to Sept. 26, 2018), which is expected in the second quarter of 2019. The revised order would be subject to further administrative or judicial review.

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

NSP-Minnesota — Mankato Energy Center Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company to purchase the 760 MW natural gas combined cycle Mankato Energy Center for approximately \$650 million. NSP-Minnesota previously contracted to purchase the energy and capacity of this facility through a PPA. The asset acquisition is anticipated to close in mid-2019 and subject to regulatory approvals from the MPUC, NDPSC, FERC and DOJ. The acquisition is projected to provide net customer savings of approximately \$50 million to \$150 million over the life of the plant.

NSP-Minnesota — Wind Repowering Acquisition — In December 2018, NSP-Minnesota filed with the MPUC to acquire the Jeffers and Community Wind North wind farms from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 to qualify for the 100% PTC benefit. The acquisition is projected to provide customer savings of approximately \$7 million over the life of the wind farms. Cost of acquisition is approximately \$135 million and pending MPUC approval.

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General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its 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.

Fuel Supply and Costs

See Item 1 — Fuel Supply and Costs for discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Key assumptions in these valuations include discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving Xcel Energy would trigger settlement accounting and could require Xcel Energy to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Environmental Matters

Environmental costs include accruals 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 and spent nuclear fuel disposal expenses, environmental monitoring and disposal of hazardous materials and waste were approximately:

\$309 million in 2018;

\$303 million in 2017; and,

\$304 million in 2016.

Xcel Energy estimates an average annual expense of approximately \$356 million from 2019 - 2023 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 included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

\$50 million in 2018;

\$61 million in 2017; and,

\$93 million in 2016.

See Item 7 — Capital Requirements for further discussion.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and disclosures in compliance with GAAP 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 and disclosures, 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 Inc. 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. Xcel Energy's 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 Xcel Energy assesses 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 Xcel Energy's results of operations, financial condition or cash flows.

As of Dec. 31, 2018 and 2017, Xcel Energy has recorded regulatory assets of \$3.8 billion and \$3.4 billion, respectively, and regulatory liabilities of \$5.6 billion and \$5.3 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. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

See Note 4 to the consolidated financial statements for further information.

Table of Contents**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. The tax accrual estimates being true-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 based on an evaluation of expected future taxable income. 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

Xcel Energy sponsors 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 a number of key assumptions (e.g., annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates). In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed by Xcel Energy..

At Dec. 31, 2018, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87%, which is consistent with the rate set at Dec. 31, 2017. The rate of return used to measure postretirement health care costs is 5.30% at Dec. 31, 2018, which represents a 50 basis point decrease from Dec. 31, 2017. Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 4.31% and postretirement health care obligations at 4.32% at Dec. 31, 2018. This represents a 68 basis point and 70 basis point increase, respectively, from Dec. 31, 2017. 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 Merrill Lynch 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 at Dec. 31, 2018, a 1% change would result in the following impact on 2018 pension costs:

	Pension Costs	
(Millions of Dollars)	+1%	-1%
Rate of return	\$(17)	\$17
Discount rate ^(a)	(6	) 7

^(a) These costs include the effects of regulation.

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 as part of the process 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, 2018 the initial medical trend cost claim assumptions for Pre-65 was 6.5% and Post-65 was 5.3%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. The period from initial trend rate until the ultimate rate is reached is four years. 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.

A 1% change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	APBO		Service and Interest Components	
(Millions of Dollars)	+1%	-1%	+1%	-1%
Health care cost trend	\$49	\$(42)	\$ 3	\$(2)

Funding requirements in 2019 are expected to remain consistent with 2018, continue at that level in 2020 and begin to decline in the following years. While investment returns were below the assumed levels in 2016 and exceeded assumed levels in 2017, investment returns were below the assumed levels in 2018.

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 13 years in 2018).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be \$114 million in 2019 and \$107 million in 2020, while the actual pension costs were \$140 million in 2018 and \$139 million in 2017. The expected decrease in 2019 and future year costs is primarily due the settlement charge experienced in 2018 and reductions in loss amortizations.

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Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2016 - 2019:

\$150 million in January 2019;

\$150 million in 2018;

\$162 million in 2017; and,

\$125 million in 2016

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, \$20 million and \$18 million during 2018, 2017 and 2016, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately \$11 million during 2019.

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.

In 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense.

- Regulatory Commissions in Colorado, 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 and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. 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.

In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction.

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 asset. The amounts recorded for AROs related to future nuclear decommissioning were \$1.968 billion in 2018 and \$1.874 billion in 2017.

NSP-Minnesota obtains periodic independent cost studies in order 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.

The most recent triennial filing was approved by the MPUC in January 2019 and resulted in no change to the accrual. The 2020 accrual will be set subsequent to a compliance filing that is expected to be submitted in July 2019.

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 expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which assumes prompt removal and dismantlement. The use of the DECON method is required by the MPUC. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

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 3.4% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on the weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

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 4% 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.

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Xcel Energy 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, 2018.

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

Derivatives, Risk Management and Market Risk

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

See Note 10 to the consolidated financial statements for further information.

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 Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to certain credit and non-performance risk.

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

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their 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. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

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

At Dec. 31, 2018, fair values by source for net commodity trading contract assets were as follows:

Futures / Forwards						
(Millions of Dollars)	SolMaturity	Maturity	Maturity	Maturity	Total	
	ofLess	1 to 3	4 to 5	Greater	Futures /	
	Fair	Years	Years	Than	Forwards	
	Value			5 Years	Fair	
	Year				Value	
NSP-Minnesota	2 \$ 3	\$ 5	\$ 2	\$ 1	\$ 11	
PSCo	2 1	—	—	—	1	
	\$ 4	\$ 5	\$ 2	\$ 1	\$ 12	

Options					
(Millions of Dollars)	SolMaturity	Maturity	Maturity	Maturity	Total
	ofLess	1 to 3	4 to 5	Greater	Options
	Fair	Years	Years	Than	Fair
	Value			5 Years	Value
	Year				
NSP-Minnesota	2 \$	— \$ 4	\$ 1	\$	— \$ 5

2 — 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 were as follows:

(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	\$16	\$10
Contracts realized or settled during the period	(10)	(5)
Commodity trading contract additions and changes during the period	11	11
Fair value of commodity trading net contract assets outstanding at Dec. 31	\$17	\$16

At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately \$16 million, whereas a 10% decrease would decrease pretax income by approximately \$16 million. At Dec. 31, 2017, a 10% increase or decrease in market prices for commodity trading contracts would have an immaterial impact.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations using VaR. VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2018	\$ 4.83	\$ 6.00	\$ 0.62	\$ 5.63	\$ 0.06
2017	0.18	3.00	0.21	0.66	0.04

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction.

NSP-Minnesota has been systematically hedging the transaction and the consolidated VaR returned below \$3 million in January 2019.

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 24% of its 2019 and approximately 54% of its 2020 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 32% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Disruptions in third party nuclear fuel supply contracts due to bankruptcies or change of contract assignments have not materially impacted NSP-Minnesota's operational or financial performance.

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

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A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately \$10 million in 2018 and \$9 million in 2017.

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

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting. See Note 10 to the consolidated financial statements for further information.

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

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

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

At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of \$14 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of \$3 million. At Dec. 31, 2017, 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 an increase in credit exposure of \$7 million.

Xcel Energy Inc. and its subsidiaries conduct credit reviews for all counterparties and employ 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 Xcel Energy's credit risk.

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. Given the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2018.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2018.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2018	2017	2016
Net cash provided by operating activities	\$3,122	\$3,126	\$3,052

Net cash provided by operating activities decreased by \$4 million for 2018 as compared to 2017. Change was primarily due to refunds associated with the TCJA and timing of certain electric and natural gas recovery mechanisms, partially offset by the change in net income (excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses)).

Net cash provided by operating activities increased by \$74 million for 2017 as compared to 2016. Increase was primarily due to higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses) and timing of customer receipts, partially offset by higher interest payments and pension contributions, refunds, timing of vendor payments and lower income tax refunds.

(Millions of Dollars)	2018	2017	2016
Net cash used in investing activities	\$(3,986)	\$(3,296)	\$(3,261)

Net cash used in investing activities increased by \$690 million for 2018 as compared to 2017. Increase was largely related to higher capital expenditures for the Rush Creek, Foxtail and Hale wind generation facilities.

Net cash used in investing activities increased by \$35 million for 2017 as compared to 2016. Increase was mainly attributable to capital expenditures related to the Rush Creek wind generation facility, partially offset by amounts for the Courtenay wind farm and less rabbi trust investments.

(Millions of Dollars)	2018	2017	2016
Net cash provided by financing activities	\$928	\$168	\$209

Net cash provided by financing activities increased by \$760 million for 2018 as compared to 2017. Increase was primarily due to lower repayments of long-term debt, proceeds from the issuances of common stock and additional debt financings, partially offset by lower short-term debt proceeds as compared to 2017.

Net cash provided by financing activities decreased by \$41 million for 2017 as compared to 2016. Decrease was primarily due to lower proceeds from debt issuances and higher dividend payments, partially offset by higher short-term debt proceeds and lower repurchases of common stock in 2017.

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Capital Requirements

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

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. Contractual obligations and other commercial commitments as of Dec. 31, 2018 were as follows:

Payments Due by Period					
(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	\$27,538	\$1,062	\$2,910	\$2,711	\$20,855
Capital lease obligations	286	14	28	24	220
Operating leases ^(a)	2,174	239	469	429	1,037
Unconditional purchase obligations ^(b)	6,700	1,457	1,990	1,432	1,821
Other long-term obligations, including current portion	716	57	98	64	497
Other short-term obligations	405	405	—	—	—
Short-term debt	1,038	1,038	—	—	—
Total contractual cash obligations	\$38,857	\$4,272	\$5,495	\$4,660	\$24,430

Included in operating lease payments are \$207 million, \$418 million, \$383 million and \$0.9 billion, for the less ^(a) than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion ^(b) of its coal, nuclear fuel and natural gas 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.

See Notes 5 and 12 to the consolidated financial statements for further information.

Capital Expenditures — Current estimated base capital expenditure programs of Xcel Energy's operating companies for the years 2019 - 2023:

Capital Forecast						
(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Subsidiary						
NSP-Minnesota	\$2,825	\$1,290	\$1,540	\$1,300	\$1,380	\$8,335
PSCo	1,370	1,380	1,335	1,395	1,530	7,010
SPS	1,130	770	460	530	635	3,525
NSP-Wisconsin	240	240	300	305	275	1,360
Other ^(a)	(50)	(70)	(25)	10	15	(120)
Total capital expenditures	\$5,515	\$3,610	\$3,610	\$3,540	\$3,835	\$20,110
Capital Forecast						

(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Function						
Electric distribution	\$775	\$865	\$1,150	\$1,245	\$1,270	\$5,305
Electric transmission	580	560	950	870	1,055	4,015
Renewables	2,315	1,105	240	—	—	3,660
Electric generation	1,070	310	480	560	545	2,965
Natural gas	430	415	420	510	595	2,370
Other ^(b)	345	355	370	355	370	1,795
Total capital expenditures	\$5,515	\$3,610	\$3,610	\$3,540	\$3,835	\$20,110

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

^(b) Amounts in other category are net of intercompany transfers.

Xcel Energy's capital expenditure program is subject to continuous review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities.

Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

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Financing Capital Expenditures through 2023 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Current estimated financing plans of Xcel Energy for 2019 - 2023:

(Millions of Dollars)

Funding Capital Expenditures

Cash from Operations*	\$13,070
New Debt**	6,190
Equity through the DRIP and Benefit Program	390
Equity through forward equity agreements	460
Base Capital Expenditures 2019 - 2023	\$20,110

Maturing Debt \$3,645

* Net of dividends and pension funding.

** Reflects a combination of short and long-term debt; net of refinancing.

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 2019, Xcel Energy announced a quarterly dividend of \$0.405 per share, which represents an increase of 6.6%. Xcel Energy's dividend policy balances the following:

• Projected cash generation;

• Projected capital investment;

• A reasonable rate of return on shareholder investment; and,

• 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 system to declare dividends. Specifically, 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, 2018	Dec. 31, 2017
Fair value of pension assets	\$2,742	\$3,088
Projected pension obligation ^(a)	3,477	3,828
Funded status	\$ (735)	\$ (740)

^(a) Excludes non-qualified plan of \$33 million and \$37 million at Dec. 31, 2018 and 2017, respectively.

Pension Assumptions	2018	2017
Discount rate	4.31 %	3.63 %
Expected long-term rate of return	6.87	6.87

Capital Sources

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

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

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 billion for Xcel Energy Inc.;
\$700 million for PSCo;
\$500 million for NSP-Minnesota;
\$400 million for SPS; and,
\$150 million for NSP-Wisconsin.

In addition, Xcel Energy Inc. has a 364-day term loan agreement to borrow up to \$500 million. As of Dec. 31, 2018, \$250 million of borrowings were outstanding with \$250 million additional borrowing capacity. In February 2019, Xcel Energy borrowed the remaining \$250 million. No additional borrowing capacity currently remains.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)		Three Months Ended Dec. 31, 2018		
Borrowing limit		\$3,250		
Amount outstanding at period end		1,038		
Average amount outstanding		500		
Maximum amount outstanding		1,038		
Weighted average interest rate, computed on a daily basis	2.76 %			
Weighted average interest rate at end of period	2.97			
(Amounts in Millions, Except Interest Rates)		Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Borrowing limit		\$3,250	\$3,250	\$2,750
Amount outstanding at period end		1,038	814	392
Average amount outstanding		788	644	485
Maximum amount outstanding		1,349	1,247	1,183
Weighted average interest rate, computed on a daily basis	2.34 %	1.35 %	0.74 %	
Weighted average interest rate at end of period	2.97	1.90	0.95	

Credit Facility Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2021 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 20, 2019, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn ^(a)	Available	Cash	Liquidity
Xcel Energy Inc.	\$ 1,500	\$ 786	\$ 714	\$ —	\$ 714
PSCo	700	224	476	1	477
NSP-Minnesota	500	152	348	1	349
SPS	400	128	272	—	272
NSP-Wisconsin	150	29	121	1	122
Total	\$3,250	\$ 1,319	\$ 1,931	\$ 3	\$ 1,934

^(a) Includes outstanding commercial paper, term loan borrowings and letters of credit.

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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, 2018 and 2017, Xcel Energy Inc. had approximately 514 million shares and 508 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Planned Financing Activity — Xcel Energy Inc. and its utility subsidiaries’ 2019 financing plans reflect the following:

Xcel Energy Inc. — approximately \$700 million of senior notes and approximately \$75 to \$80 million of equity through the DRIP and benefit programs;

NSP-Minnesota — approximately \$900 million of first mortgage bonds;

PSCo — approximately \$800 million of first mortgage bonds; and,

SPS — approximately \$300 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward sale agreements in connection with a completed \$459 million public offering of 9.4 million shares of Xcel Energy common stock. The initial forward agreement was for 8.1 million shares with an additional forward agreement of 1.2 million shares exercised at the option of the banking counterparty. At Dec. 31, 2018, the forward agreements could have been settled with physical delivery of 9.4 million common shares to the banking counterparty in exchange for cash of \$456 million. The forward instruments could also have been settled at Dec. 31, 2018 with delivery of approximately \$24 million of cash or approximately 0.5 million shares of common stock to the banking counterparty, 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 2018 public offering price for Xcel Energy’s common stock of \$49.00, 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 instruments are outstanding.

Xcel Energy may settle the forward agreements at any time up to the maturity date of February 7, 2020. The cash proceeds, depending on the timing of settlement, are expected to be approximately \$450 million to \$460 million.

Forward equity instruments were accounted for as stockholders’ equity and recorded at fair value at the execution of the forward agreements, and will not be subsequently adjusted for changes in fair value until settlement.

ATM Equity Offering — In 2018, Xcel Energy issued 4.7 million shares of common stock with net proceeds of \$224.7 million through the at the market program. In addition, total transaction fees of \$1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy also plans to issue approximately \$75 to \$80 million of equity, each year, through the DRIP and benefit programs during the five-year forecast time period.

Long-Term Borrowings and Other Financing Instruments — See Note 5 to the consolidated financial statements for further information.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

2019 GAAP and ongoing earnings guidance is a range of \$2.55 to \$2.65 per share.^(a) Key assumptions:

Constructive outcomes in all rate case and regulatory proceedings.

Normal weather patterns for the year.

Weather-normalized retail electric sales are projected to be relatively consistent with 2018 levels.

Weather-normalized retail natural gas sales are projected to be within a range of 0.0% to 1.0% over 2018 levels.

Capital rider revenue is projected to increase \$115 million to \$125 million (net of PTCs) over 2018 levels. PTCs are flowed back to customers, primarily through capital riders as reductions to electric margin.

Purchase capacity costs are expected to decline \$25 million to \$30 million compared with 2018 levels.

O&M expenses are projected to be consistent with 2017 levels.

Depreciation expense is projected to increase approximately \$120 million to \$130 million over 2018 levels.

Depreciation expense includes \$34 million for the amortization of a prepaid pension asset at PSCo, which is TCJA related and will not impact earnings.

Property taxes are projected to increase approximately \$15 million to \$25 million over 2018 levels.

Interest expense (net of AFUDC — debt) is projected to increase \$90 million to \$100 million over 2018 levels.

AFUDC — equity is projected to decrease approximately \$20 million to \$30 million from 2018 levels.

The ETR is projected to be approximately 6% to 8%. The ETR reflects benefits of PTCs which are flowed back to customers through electric margin.

Assumptions do not include the impact for the upcoming adoption of the new lease accounting standard, effective 2019. Xcel Energy does not expect changes in the accounting for leases to impact earnings, but it may result in variations in certain line items within the statement of income.

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

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See 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.

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Management Report on Internal Controls 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, 2018. 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, 2018, 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 audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE /s/ ROBERT C. FRENZEL

Ben Fowke

Robert C. Frenzel

Chairman,

President and

Executive Vice President,

Chief Executive

Chief Financial Officer

Officer

Feb. 22, 2019

Feb. 22, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders 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, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 22, 2019

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

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

	Year Ended Dec. 31		
	2018	2017	2016
Operating revenues			
Electric	\$9,719	\$9,676	\$9,500
Natural gas	1,739	1,650	1,531
Other	79	78	76
Total operating revenues	11,537	11,404	11,107
Operating expenses			
Electric fuel and purchased power	3,854	3,757	3,718
Cost of natural gas sold and transported	843	823	733
Cost of sales — other	35	34	36
Operating and maintenance expenses	2,352	2,270	2,300
Conservation and demand side management program expenses	290	273	245
Depreciation and amortization	1,642	1,479	1,303
Taxes (other than income taxes)	556	545	532
Total operating expenses	9,572	9,181	8,867
Operating income	1,965	2,223	2,240
Other expense, net	(14)	(10)	(18)
Equity earnings of unconsolidated subsidiaries	35	30	42
Allowance for funds used during construction — equity	108	75	60
Interest charges and financing costs			
Interest charges — includes other financing costs of \$25, \$24 and \$25, respectively	700	663	647
Allowance for funds used during construction — debt	(48)	(35)	(27)
Total interest charges and financing costs	652	628	620
Income before income taxes	1,442	1,690	1,704
Income taxes	181	542	581
Net income	\$1,261	\$1,148	\$1,123
Weighted average common shares outstanding:			
Basic	511	509	509
Diluted	511	509	509
Earnings per average common share:			
Basic	\$2.47	\$2.26	\$2.21
Diluted	2.47	2.25	2.21

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2018	2017	2016
Net income	\$1,261	\$1,148	\$1,123
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of \$(2), \$(2), and \$(5), respectively	(6	) (3	) (8
Amortization of losses included in net periodic benefit cost, net of tax of \$3, \$5, and \$2, respectively	9	7	4
	3	4	(4
Derivative instruments:			
Net fair value decrease, net of tax of \$(2), \$0, and \$0, respectively	(5	) —	—
Reclassification of losses to net income, net of tax of \$1, \$2, and \$2, respectively	3	3	4
	(2	) 3	4
Other comprehensive income	1	7	—
Comprehensive income	\$1,262	\$1,155	\$1,123

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net income	\$1,261	\$1,148	\$1,123
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,659	1,495	1,319
Nuclear fuel amortization	122	114	117
Deferred income taxes	218	640	587
Allowance for equity funds used during construction	(108)	(75)	(60)
Equity earnings of unconsolidated subsidiaries	(35)	(30)	(42)
Dividends from unconsolidated subsidiaries	37	41	46
Provision for bad debts	42	39	39
Share-based compensation expense	45	57	41
Net realized and unrealized hedging and derivative transactions	22	2	8
Changes in operating assets and liabilities:			
Accounts receivable	(105)	(60)	(83)
Accrued unbilled revenues	9	(34)	(75)
Inventories	(65)	(3)	1
Other current assets	18	9	61
Accounts payable	90	43	118
Net regulatory assets and liabilities	223	(16)	(19)
Other current liabilities	(61)	(38)	20
Pension and other employee benefit obligations	(179)	(133)	(91)
Other, net	(71)	(73)	(58)
Net cash provided by operating activities	3,122	3,126	3,052
Investing activities			
Utility capital/construction expenditures	(3,957)	(3,244)	(3,195)
Purchases of investment securities	(853)	(1,697)	(547)
Proceeds from the sale of investment securities	833	1,669	479
Other, net	(9)	(24)	2
Net cash used in investing activities	(3,986)	(3,296)	(3,261)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	225	422	(454)
Proceeds from issuance of long-term debt	1,675	1,518	2,424
Repayments of long-term debt, including reacquisition premiums	(452)	(1,030)	(1,036)
Proceeds from issuance of common stock	230	—	—
Repurchases of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other, net	(19)	(18)	(12)
Net cash provided by financing activities	928	168	209
Net change in cash and cash equivalents	64	(2)	—
Cash and cash equivalents at beginning of period	83	85	85
Cash and cash equivalents at end of period	\$147	\$83	\$85

Supplemental disclosure of cash flow information:

Cash paid for interest (net of amounts capitalized)	\$(633)	\$(616)	\$(592)
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Cash received for income taxes, net	27	44	62
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Supplemental disclosure of non-cash investing and financing transactions:

Accrued property, plant and equipment additions	\$388	\$464	\$311
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Inventory transfers to property, plant and equipment	129	63	107
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Allowance for equity funds used during construction	108	75	61
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Issuance of common stock for reinvested dividends and equity awards	67	31	29
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See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(amounts in millions, except share and per share)

	Dec. 31	
	2018	2017
Assets		
Current assets		
Cash and cash equivalents	\$ 147	\$ 83
Accounts receivable, net	860	797
Accrued unbilled revenues	755	764
Inventories	548	610
Regulatory assets	464	424
Derivative instruments	87	44
Prepaid taxes	79	68
Prepayments and other	154	183
Total current assets	3,094	2,973
Property, plant and equipment, net	36,944	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,317	2,397
Regulatory assets	3,326	3,005
Derivative instruments	34	48
Deposits and other	272	278
Total other assets	5,949	5,728
Total assets	\$45,987	\$43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	\$406	\$457
Short-term debt	1,038	814
Accounts payable	1,237	1,243
Regulatory liabilities	436	239
Taxes accrued	450	448
Accrued interest	174	174
Dividends payable	195	183
Derivative instruments	61	29
Other	463	501
Total current liabilities	4,460	4,088
Deferred credits and other liabilities		
Deferred income taxes	4,165	3,845
Deferred investment tax credits	54	58
Regulatory liabilities	5,187	5,083
Asset retirement obligations	2,568	2,475
Derivative instruments	129	126
Customer advances	199	193
Pension and employee benefit obligations	994	1,042
Other	206	145

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Total deferred credits and other liabilities	13,502	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	15,803	14,520
Common stock — 1,000,000,000 shares authorized of \$2.50 par value; 514,036,787 and 507,762,881 shares outstanding at Dec. 31, 2018 and 2017, respectively	1,285	1,269
Additional paid in capital	6,168	5,898
Retained earnings	4,893	4,413
Accumulated other comprehensive loss	(124)	(125)
Total common stockholders' equity	12,222	11,455
Total liabilities and equity	\$45,987	\$43,030

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(amounts in millions, shares in thousands)

	Common Stock Issued			Retained Earnings	Accumulated	Total
	Shares	Par Value	Additional Paid In Capital		Other Comprehensive Loss	Common Stockholders' Equity
Balance at Dec. 31, 2015	507,536	\$ 1,269	\$ 5,889	\$ 3,553	\$ (110)	\$ 10,601
Net income				1,123		1,123
Dividends declared on common stock (\$1.36 per share)				(694)		(694)
Issuances of common stock	486	1	15			16
Repurchases of common stock	(799)	(2)	(30)			(32)
Share-based compensation			7			7
Balance at Dec. 31, 2016	507,223	\$ 1,268	\$ 5,881	\$ 3,982	\$ (110)	\$ 11,021
Net income				1,148		1,148
Other comprehensive income					7	7
Dividends declared on common stock (\$1.44 per share)				(736)		(736)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			16	(3)		13
Adoption of ASU No. 2018-02				22	(22)	—
Balance at Dec. 31, 2017	507,763	\$ 1,269	\$ 5,898	\$ 4,413	\$ (125)	\$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock (\$1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	\$ 1,285	\$ 6,168	\$ 4,893	\$ (124)	\$ 12,222

See Notes to Consolidated Financial Statements

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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 in 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 Eloigne and Capital Services. 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 Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Nicollet Project Holdings LLC and Xcel Energy Services Inc. Xcel Energy Inc. 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.

Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries. Xcel Energy has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 3 for further information.

Xcel Energy's 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.

Xcel Energy has evaluated events occurring after Dec. 31, 2018 up to the date of issuance of these consolidated financial statements. Statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on 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 and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.'s 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 of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. 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 from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations, financial condition or cash flows. See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax 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.

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 which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

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 it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes.

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.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its 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.

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Xcel Energy reports interest and penalties related to income taxes within the other income and 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 — 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 are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

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.

Xcel Energy records depreciation expense using the straight-line method over the plant's 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. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1% for 2018, 3.1% for 2017 and 2.9% for 2016.

See Note 3 for further information.

AROs — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement 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 depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers the decommissioning costs of its nuclear power plants over each facility's expected service life 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 the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Note 10 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 liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as 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 proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Future costs of restoring sites are 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.

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 on a systematic basis 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. Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees.

Xcel Energy's utility subsidiaries recognize sales to customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges are recorded on a net basis in cost of sales.

See Note 6 for further information.

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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, 2018 and 2017, the allowance for bad debts was \$55 million and \$52 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

	Dec.	Dec.
(Millions of Dollars)	31,	31,
	2018	2017
Inventories		
Materials and supplies	\$ 271	\$ 311
Fuel	170	186
Natural gas	107	113
	\$ 548	\$ 610

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish 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, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments 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; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense.

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

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 Xcel Energy's 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. AFUDC 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 for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP/DSM programs) qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, such as collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue