XCEL ENERGY INC
Form 10-K
February 22, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
x 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	Name of each exchange on which registered
Common Stock, $2.50 par value per share	Nasdaq Stock Market LLC

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x 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). x 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. x 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 x 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	Windsource® 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, municipals 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 Transmission	LSP Transmission Holdings, LLC
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
SO2	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 res 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 Gas Supply	NSP System Gas Transportation and Storage [a]	PSCo Gas Supply [b]	PSCo Gas Transportation and Storage [a]	SPS Gas Supply	SPS 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 - 2023	2019 - 2040	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.

(b) Majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services 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 trued-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 CO_2 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

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EXECUTIVE 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.	

			September 2011 - August 2014
Timothy O'Connor	59	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	February 2013 - Present
Judy M. Poferl	59	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	January 2015 - Present
		Vice President, Corporate Secretary, Xcel Energy Inc.	May 2013 - December 2014
Jeffrey S. Savage	47	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 - Present
		Vice President, Controller, Xcel Energy Inc.	September 2011 - December 2014
Mark E. Stoering	58	President and Director, NSP-Wisconsin	January 2015 - Present
		President, Director and Chief Executive Officer, NSP-Wisconsin	January 2012 - December 2014
Scott M. Wilensky	62	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, General Counsel, Xcel Energy Inc.	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 CO_2 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 outdating 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:				

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.
[(g)] Generation capability is based on the maximum output level of wind units, including the Rush Creek Wind Project. 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:			

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

(a) 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.

(b) 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.

(c) 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 coals 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:

Diluted Earnings (Loss) Per Share	2018 GAAP and Ongoing Diluted EPS	2017 GAAP Diluted EPS	Impact of TCJA [a]	Ongoing Diluted EPS	2016 GAAP and Ongoing Diluted EPS
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.

(b) ETR includes the impact of an additional $20 million of wind PTCs for the twelve months ended Dec. 31, 2017, 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 GAAP and Ongoing ROE	2017 GAAP ROE	Impact of the TCJA	Ongoing 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 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 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 %	5.7 %	5.4 %
Electric C&I	1.5	1.1	5.4	3.2	2.4
Total retail electric sales	2.2	2.5	5.9	3.9	3.2
Firm natural gas sales	9.3	14.6	N/A	13.1	11.3

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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

(Millions of Dollars)	2018 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)

(Millions of Dollars)	2017 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

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

(Millions of Dollars)	2017 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:

(Millions of Dollars)	2018 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:

(Millions of Dollars)	2017 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.
SPS	Electric	December 2018	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	Pending	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. 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. In October 2018, the CPUC approved a settlement to extend the PSIA rider through 2021.
DSM Incentive	Electric & Natural Gas	$11	April 2018	Received	PSCo earned an electric and natural gas DSM incentive of $9 million and $2 million, respectively, for achieving its 2017 savings goals.
SPS (PUCT)					
Rate Case	Electric	$54		Received	

			August 2017		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	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.
Rate Case	Electric	$43	October 2017	Received/Pending	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. 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.

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.

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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 trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

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

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized 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:

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

(Millions) of Dollars)	Options Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
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

(a) Included in operating lease payments are $207 million, $418 million, $383 million and $0.9 billion, for the less 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.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion 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.

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

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 Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2019	Feb. 22, 2019

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)
Cash received for income taxes, net	27	44	62
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$388	$464	$311
Inventory transfers to property, plant and equipment	129	63	107
Allowance for equity funds used during construction	108	75	61
Issuance of common stock for reinvested dividends and equity awards	67	31	29

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

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				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	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.

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:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 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 earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

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

Emission Allowances — Emission allowances are recorded at cost plus broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

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

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

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

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2. Accounting Pronouncements

Recently Issued

Leases — In 2016, the FASB issued Leases, Topic 842 (ASU No. 2016-02), which requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. Adoption will occur on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions of whether agreements existing before the adoption date contain leases, and whether existing leases are operating or capital/finance leases. Xcel Energy expects to utilize other expedients offered by the new standard and Leases, Topic 842 (ASU No. 2018-11), including elections to not recognize short term leases on the consolidated balance sheet for certain classes of assets and to implement the standard on a prospective basis. Xcel Energy's implementation of the new guidance is substantially complete, and is expected to result in the recognition of approximately $2 billion of right-of-use assets and lease liabilities in the first quarter of 2019 for operating leases for the use of real estate, equipment and certain natural gas generating facilities operated under PPAs. The implementation is not expected to have a significant impact on Xcel Energy's consolidated financial statements, other than first-time recognition of these operating leases on the consolidated balance sheet.

Recently Adopted

Revenue Recognition — In 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. Xcel Energy implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The implementation did not have a material impact on Xcel Energy's consolidated financial statements, other than increased disclosures regarding revenues related to contracts with customers.

Classification and Measurement of Financial Instruments — In 2016, the FASB issued Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01), which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Xcel Energy implemented the guidance on Jan. 1, 2018 and the adoption impacts were not material.

Presentation of Net Periodic Benefit Cost — In 2017, the FASB issued Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07), which establishes that only the service cost portion of pension cost may be presented as a component of operating income. In addition, only the service cost portion of pension cost is eligible for capitalization. As a result of regulatory accounting treatment, a similar amount of pension cost, including non-service components, will be recognized consistent with historical ratemaking and the impacts of adoption are limited to changes in classification of non-service costs in the consolidated statements of income.

Xcel Energy implemented the new guidance on Jan. 1, 2018. As a result, $33 million and $26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other expense, net on the consolidated statements of income for 2017 and 2016, respectively. Xcel Energy used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Property, Plant and Equipment

Major classes of property, plant and equipment:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment		
Electric plant	$41,472	$39,016
Natural gas plant	6,210	5,800
Common and other property	2,154	2,013
Plant to be retired [(a)]	322	11

CWIP	2,091	2,087
Total property, plant and equipment	52,249	48,927
Less accumulated depreciation	(15,659)	(15,000)
Nuclear fuel	2,771	2,697
Less accumulated amortization	(2,417)	(2,295)
	$36,944	$34,329

(a) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in approximately 2022 and 2025, respectively. PSCo also expects Craig Unit 1 to be retired early in 2025. Amounts are presented net of accumulated depreciation.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2018:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	$ 604	$ 415	$ 1	59 %
Sherco Common Facilities	145	100	1	80
Other	5	4	—	59
Electric Transmission:				
CapX2020 Transmission	960	73	2	51
Other	11	2	—	50
Total NSP-Minnesota	$ 1,725	$ 594	$ 4	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric Transmission:				
La Crosse, WI to Madison, WI	$ 175	$ 2	$ —	37 %
CapX2020 Transmission	169	15	2	81
Total NSP-Wisconsin	$ 344	$ 17	$ 2	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric Generation:				
Hayden Unit 1	$ 153	$ 76	$ —	76 %
Hayden Unit 2	149	68	—	37
Hayden Common Facilities	41	21	—	53
Craig Units 1 and 2	81	40	—	10
Craig Common Facilities	39	21	—	7
Comanche Unit 3	886	130	—	67
Comanche Common Facilities	28	3	—	82
Electric Transmission:				
Transmission and other facilities	183	63	1	Various
Gas Transportation:				
Rifle, CO to Avon, CO	22	7	—	60
Gas Transportation Compressor	8	1	—	50
Total PSCo	$ 1,590	$ 430	$ 1	

Each company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

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4. Regulatory Assets and Liabilities

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

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Assets			Current	Non-current	Current	Non-current
Pension and retiree medical obligations	11	Various	$87	$1,500	$91	$1,499
Net AROs [a]	1, 12	Plant lives	—	452	—	301
Excess deferred taxes - TCJA	7	Various	—	296	—	254
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	264	—	244
Environmental remediation costs	1, 12	Various	17	155	16	165
Depreciation differences		One to thirteen years	18	107	20	69
Benson biomass PPA termination and asset purchase		Ten years	10	86	—	—
Contract valuation adjustments [b]	1, 10	Term of related contract	17	77	21	93
Laurentian biomass PPA termination		Five years	18	73	—	—
Purchased power contract costs		Term of related contract	4	63	3	67
PI EPU		Sixteen years	3	56	3	58
Losses on reacquired debt		Term of related debt	4	44	5	48
State commission adjustments		Plant lives	1	29	1	29
Conservation programs [c]	1	One to two years	42	28	50	32
Property tax		Various	14	10	8	24
Nuclear refueling outage costs	1	One to two years	37	14	49	20
Deferred purchased natural gas and electric energy costs		One to three years	57	13	21	13
Renewable resources and environmental initiatives		One to two years	39	9	48	10
Sales true up and revenue decoupling		One to two years	38	7	37	12
Gas pipeline inspection and remediation costs		One to two years	28	3	24	12
Other		Various	30	40	27	55
Total regulatory assets			$464	$3,326	$424	$3,005

[a] Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

[b] Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

[c] Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Liabilities			Current	Non-current	Current	Non-current
Deferred income tax adjustments and TCJA refunds [a]	7	Various	$157	$3,715	$—	$3,790
Plant removal costs	1, 12	Plant lives	—	1,175	—	1,131

Effects of regulation on employee benefit costs [b]		Various	—	137	—	46
Renewable resources and environmental initiatives		Various	9	54	19	60
ITC deferrals [c]	1	Various	—	40	—	23
Deferred electric, natural gas and steam production costs		Less than one year	102	—	104	—
Contract valuation adjustments [d]	1, 10	Less than one year	26	—	30	—
Conservation programs [e]	1	Less than one year	36	—	23	—
DOE settlement		Less than one year	19	—	18	—
Other		Various	87	66	45	33
Total regulatory liabilities [f]			$436	$5,187	$239	$5,083

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes regulatory amortization and certain TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset at Dec. 31, 2018.

(c) Includes impact of lower federal tax rate due to the TCJA.

(d) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

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

(f) Revenue subject to refund of $29 million and $15 million for 2018 and 2017, respectively, is included in other current liabilities.

At Dec. 31, 2018 and 2017, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $178 million and $212 million at Dec. 31, 2018 and 2017, respectively, of past expenditures not earning a return. Amounts largely related to purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

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5. Borrowings and Other Financing Instruments
Short-Term Borrowings
Short-Term Debt — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper, term loan borrowings and letters of credit under their credit facilities.
Short-term debt borrowings outstanding for Xcel Energy were as follows:

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

Term Loan Agreement — In December 2018, Xcel Energy Inc. renewed its $500 million 364-Day Term Loan Agreement with $250 million outstanding. In February 2019, Xcel Energy borrowed the remaining amount. No additional capacity remains as loans borrowed and repaid may not be redrawn. The loan is unsecured and matures Dec. 3, 2019. Xcel Energy has an option to request an extension through Dec. 2, 2020. Term loan includes one financial covenant, requiring Xcel Energy’s consolidated funded debt to total capitalization ratio to be less than or equal to 65 percent. Interest is at a rate equal to either (i) the Eurodollar rate, plus 50.0 basis points, or (ii) an alternate base rate. Xcel Energy is also required to pay a commitment fee equal to 10 basis points per annum on the unborrowed portion.
Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2018 and 2017, there were $49 million and $30 million of letters of credit outstanding. Amounts approximate their fair value.
Credit Facilities — Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.
Features of the credit facilities:

	Debt-to-Total Capitalization Ratio[a] 2018	2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested [b]
Xcel Energy Inc. [c]	58 %	58 %	$ 200	2
NSP-Wisconsin	48	47	N/A	1
NSP-Minnesota	48	48	100	2
SPS	46	46	50	2
PSCo	46	44	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.

(b) All extension requests are subject to majority bank group approval.

(c) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2018, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2018:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,500	$488	$ 1,012
PSCo	700	317	383
NSP-Minnesota	500	187	313
SPS	400	44	356
NSP-Wisconsin	150	51	99
Total	$ 3,250	$1,087	$ 2,163

(a) These credit facilities mature in June 2021, with the exception of Xcel Energy's Inc.'s 364-day term loan agreement which expires in December 2019.

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

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2018 and 2017.

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Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Xcel Energy Inc.					
Unsecured senior notes	2020 - 2041	2.40% - 6.50%	1.20% - 6.50%	$3,400	$2,900
Elimination of PSCo capital lease obligation with affiliates				(60)	(62)
Unamortized discount				(5)	(2)
Unamortized debt issuance cost				(21)	(20)
Current maturities (Capital lease obligation)				2	2
Total				$3,316	$2,818

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Minnesota					
Mortgage bonds	2020 - 2047	2.15% - 7.13%	2.15% - 7.13%	$5,000	$5,000
Unamortized discount				(21)	(22)
Unamortized debt issuance cost				(42)	(45)
Current maturities				—	—
Total				$4,937	$4,933

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Wisconsin					
Mortgage bonds	2024 - 2048	3.3% - 6.38%	3.3% - 6.38%	$800	$750
City of La Crosse resource recovery bond	2021	6.00%	6.00%	19	19
Other				—	2
Unamortized discount				(3)	(3)
Unamortized debt issuance cost				(9)	(7)
Current maturities				—	(151)
Total				$807	$610

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
PSCo					
Capital lease obligations	2025 - 2060	11.20% - 14.30%	11.20% - 14.30%	$145	$151
Mortgage bonds	2019 - 2048	2.25% - 6.50%	2.25% - 6.50%	4,900	4,500
Unamortized discount				(14)	(13)
Unamortized debt issuance cost				(33)	(29)
Current maturities				(406)	(306)
Total				$4,592	$4,303

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
SPS					
Mortgage bonds	2024 - 2048	3.30% - 4.50%	3.30% - 4.50%	$1,800	$1,500
Unsecured senior notes	2033 - 2036	6.00%	6.00% - 8.75%	350	350
Unamortized discount				(4)	(2)

Unamortized debt issuance cost				(20)	(18)
Current maturities				—	—
Total				$2,126	$1,830

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Other Subsidiaries					
Various Eloigne Co. affordable housing project notes	2019 - 2052	0.00% - 6.90%	0.00% - 7.05%	$26	$28
Current maturities				(1)	(2)
Total				$25	$26

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Maturities of long-term debt:

(Millions of Dollars)	
2019	$ 406
2020	1,257
2021	425
2022	902
2023	653

2018 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
Xcel Energy Inc.	$500 million	Senior Notes	4.00 %	June 15, 2028
PSCo	350 million	First mortgage bonds	3.70	June 15, 2028
PSCo	350 million	First mortgage bonds	4.10	June 15, 2048
NSP-Wisconsin	200 million	First mortgage bonds	4.20	Sept. 1, 2048
SPS	300 million	First mortgage bonds	4.40	Nov 15, 2048

2017 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
PSCo	$400 million	First mortgage bonds	3.80 %	June 15, 2047
SPS	450 million	First mortgage bonds	3.70	Aug. 15, 2047
NSP-Minnesota	600 million	First mortgage bonds	3.60	Sept. 15, 2047
NSP-Wisconsin	100 million	First mortgage bonds	3.75	Dec. 1, 2047

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 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 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 agreements at any time up to the maturity date of February 7, 2020. Depending on settlement timing, cash proceeds are expected to be approximately $450 million to $460 million.

Forward equity instruments were recognized within stockholders' equity at fair value at execution of the agreements, and will not be subsequently adjusted until settlement.

ATM Equity Offering — 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, transaction fees of $1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy issued $38.5 million and $39.2 million of equity through the DRIP program during the years ended Dec. 31, 2018 and 2017 respectively. Program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Deferred Financing Costs — Deferred financing costs of approximately $126 million and $119 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2018 and 2017, respectively.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2018 and 2017
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

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

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) 2018	Common Stock Outstanding (Shares) 2017
1 billion	$ 2.50	514,036,787	507,762,881

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

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS. Requirements and actuals as of Dec. 31, 2018:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2018
NSP-Minnesota	47.1 %	57.5 %	52.3 %
NSP-Wisconsin	51.5	N/A	51.8
SPS [(a)]	45.0	55.0	54.4

(a) SPS excludes short-term debt.

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1.0 billion	$ 10.7 billion	$ 11.5 billion
NSP-Wisconsin [(a)]	11.5 million	1.7 billion	N/A
SPS [(b)]	605.7 million	4.7 billion	N/A

(a) NSP-Wisconsin cannot pay annual dividends in excess of approximately $55 million if its average equity-to-total capitalization ratio falls below the commission authorized level.

(b) SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

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

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Authorizations as of Dec. 31, 2018:

	Amount Authorized to Issue		
	Long-Term Debt	Short-Term Debt	
NSP-Minnesota	52.93% of total capitalization (a)	$1.725	billion (a)
NSP-Wisconsin	$— (b)	150	million
SPS	— (b)	600	million
PSCo	1.1 billion	800	million

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

(b) SPS and NSP-Wisconsin will file for additional long-term debt authorization.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues (subsequent to adoption of the revised revenue guidance) consists of the following:

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$2,919	$988	$ 38	$3,945
C&I	4,874	524	25	5,423
Other	134	—	6	140
Total retail	7,927	1,512	69	9,508
Wholesale	791	—	—	791
Transmission	523	—	—	523
Other	98	100	—	198
Total revenue from contracts with customers	9,339	1,612	69	11,020
Alternative revenue and other	380	127	10	517
Total revenues	$9,719	$1,739	$ 79	$11,537

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy, generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the consolidated financial statements.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law in December 2017 included:

- $2.7 billion ($3.8 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over an estimated weighted average period of approximately 30 years;
- $254 million and $174 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and,
- $23 million of total estimated income tax expense related to the tax rate change on certain non-plant deferred taxes and all other 2017 income statement impacts of the federal tax reform.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Tax Loss Carryback Claims — In 2012 - 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

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

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy’s NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

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

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As of Dec. 31, 2018, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2010
Wisconsin	2014

- In the fourth quarter of 2018, the Minnesota audit of tax years 2010 - 2014 concluded with no material adjustments.
- In the third quarter of 2018, the Wisconsin audit of tax years 2012 - 2013 concluded with no material adjustments. In the fourth quarter of 2018, Wisconsin began an audit of tax years 2014 - 2016. No material adjustments have been proposed.
- No other state income tax audits were in progress as of Dec. 31, 2018.

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

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 28	$ 20
Unrecognized tax benefit — Temporary tax positions	9	19
Total unrecognized tax benefit	$ 37	$ 39

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$39	$134	$121
Additions based on tax positions related to the current year	9	6	8
Reductions based on tax positions related to the current year	(4)	(4)	—
Additions for tax positions of prior years	2	15	10
Reductions for tax positions of prior years	(4)	(105)	(5)
Settlements with taxing authorities	(5)	(7)	—
Balance at Dec. 31	$37	$39	$134

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

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$(35)	$(31)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $24 million and $13 million at Dec. 31, 2018 and Dec 31, 2017, respectively.

As the IRS Appeals and federal and state audits progress and other state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $28 million in the next 12 months.

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

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Payable for interest related to unrecognized tax benefits at Jan. 1	$ —	$(3)	$—
Interest income (expense) related to unrecognized tax benefits	—	3	(3)

Payable for interest related to unrecognized tax benefits at Dec. 31	$ —	$ —	$ (3)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, 2017 or 2016.

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

(Millions of Dollars)	2018	2017
Federal NOL carryforward	$ —	$ 1,072
Federal tax credit carryforwards	553	517
Valuation allowances for federal credit carryforwards	(5)	(5)
State NOL carryforwards	1,104	1,592
Valuation allowances for state NOL carryforwards	(50)	(55)
State tax credit carryforwards, net of federal detriment [(a)]	89	90
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(69)	(68)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2018 and 2017.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $18 million as of Dec. 31, 2018 and 2017.

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2019 and 2037.

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

Effective income tax rate for years ended Dec. 31:

	2018	2017 [(a)]	2016 [(a)]
Federal statutory rate	21.0 %	35.0 %	35.0 %
State income tax on pretax income, net of federal tax effect	5.0	4.1	4.1
Increases (decreases) in tax from:			
Regulatory differences - ARAM [(b)]	(5.8)	(0.1)	(0.1)
Wind production tax credits recognized	(5.2)	(4.7)	(3.4)
Other tax credits recognized, net of federal income tax expense	(2.0)	(1.0)	(0.8)
Regulatory differences - other utility plant items	(1.0)	(0.7)	(0.5)
Regulatory differences - Deferral of ARAM [(c)]	0.6	—	—
Change in unrecognized tax benefits	0.4	(0.6)	0.2
Tax reform	—	1.4	—
Other, net	(0.4)	(1.3)	(0.4)
Effective income tax rate	12.6 %	32.1 %	34.1 %

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

(b) ARAM is a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

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

(Millions of Dollars)	2018	2017	2016
Current federal tax (benefit) expense	$(34)	$1	$(3)
Current state tax expense (benefit)	8	(11)	(4)
Current change in unrecognized tax (benefit) expense	(6)	(83)	6
Deferred federal tax expense	122	460	477
Deferred state tax expense	85	107	112
Deferred change in unrecognized tax expense (benefit)	11	73	(2)
Deferred investment tax credits	(5)	(5)	(5)
Total income tax expense	$181	$542	$581

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

(Millions of Dollars)	2018	2017	2016
Deferred tax expense (benefit) excluding items below	$320	$(2,939)	$631
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(102)	3,583	(45)
Tax (expense) benefit allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	—	(4)	1
Deferred tax expense	$218	$640	$587

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

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$5,082	$4,960
Regulatory assets	599	565
Pension expense	178	199
Other	64	57
Total deferred tax liabilities	$5,923	$5,781
Deferred tax assets:		
Regulatory liabilities	$879	$886
Tax credit carryforward	642	607
NOL carryforward	51	293
NOL and tax credit valuation allowances	(79)	(77)
Other employee benefits	124	132
Deferred ITCs	16	17
Rate refund	60	10
Other	65	68
Total deferred tax assets	$1,758	$1,936
Net deferred tax liability	$4,165	$3,845

8. Share-Based Compensation

Incentive Plans Including Share-Based Compensation — Xcel Energy Inc. has three incentive plans that include share-based payment elements. Plans and authorized equity shares for awards:

- Omnibus Incentive Plan - 7.0 million shares;
- Long-Term Incentive Plan - 8.3 million shares; and,
- Executive Annual Incentive Award Plan - 1.2 million shares.

Restricted Stock — The Executive Annual Incentive Award Plan and Omnibus Incentive Plan allow certain employees to elect to receive shares of common or restricted stock. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.’s stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2018	2017	2016
Granted shares	18	15	20
Grant date fair value	$44.68	$42.00	$38.82

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2018	44	$ 39.71
Granted	18	44.68
Forfeited	—	—
Vested	(27)	37.25
Dividend equivalents	1	46.27
Nonvested restricted stock at Dec. 31, 2018	36	44.29

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. Long-Term Incentive Plan and the Omnibus Incentive Plan. These plans include various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if the vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.3 million time-based equity shares subject only to service conditions were granted annually in 2018, 2017 and 2016, respectively.

The performance conditions for a portion of the awards granted from 2016 to 2018 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200 percent depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2018	2017	2016
Granted units	500	503	522
Weighted average grant date fair value	$47.60	$41.02	$36.00

Equity awards vested:

(Units in Thousands)	2018	2017	2016
Vested Units	475	467	530
Total Fair Value	$23,393	$22,459	$21,575

Changes in the nonvested portion of equity award units for 2018:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2018	995	$ 38.48
Granted	500	47.60
Forfeited	(126)	41.74
Vested	(475)	35.92
Dividend equivalents	45	40.74
Nonvested Units at Dec. 31, 2018	939	44.30

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Stock Equivalent Units — Non-employee members of Xcel Energy Inc. Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of Xcel Energy Inc. common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their cash fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2018	2017	2016
Granted units	36	51	49
Weighted average grant date fair value	$45.44	$46.05	$40.68

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2018	753	$ 29.83
Granted	36	45.44
Units distributed	(123)	31.21
Dividend equivalents	22	46.40
Stock equivalent units at Dec. 31, 2018	688	30.93

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Long-Term Incentive Plan and Omnibus Incentive Plan. The plans allow Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a 22-member utilities peer group for 2016 - 2018 awards. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2018	2017	2016
Awards granted	239	240	264

TSR liability awards settled:

(In Thousands)	2018	2017	2016
Awards settled	482	454	354
Settlement amount (cash, common stock and deferred amounts)	$21,534	$19,083	$13,724

TSR liability awards of $8 million were settled in cash in 2018.

Share-Based Compensation Expense — Vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target, other than for restricted stock. Additionally, approximately 0.3 million of equity award units were granted annually in 2016 - 2018, with vesting subject only to service conditions of three years. Generally these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. Grant date fair value of equity awards is expensed over the service period.

TSR liability awards have been historically settled partially in cash, and do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

Compensation costs related to share-based awards:

(Millions of Dollars)	2018	2017	2016
Compensation cost for share-based awards [(a)]	$ 45	$ 57	$ 41

Tax benefit recognized in income	12	22	16

[a] Compensation costs for share-based payment are included in O&M expense.

There was approximately $38 million in 2018 and $44 million in 2017 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents related to forward equity agreements and certain equity awards in share-based compensation arrangements. Common stock equivalents include commitments to issue common stock related to time based equity compensation awards.

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

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

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

Diluted common shares outstanding included common stock equivalents of 0.5 million, 0.6 million and 0.7 million shares for 2018, 2017 and 2016.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

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

Specific valuation methods include:

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

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

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

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

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

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

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

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

Non-Derivative Fair Value Measurements

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

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

Unrealized gains for the nuclear decommissioning fund were $450 million and $560 million as of Dec. 31, 2018 and 2017, respectively, and unrealized losses were $45 million and $7 million as of Dec. 31, 2018 and 2017, respectively.

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

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$24	$24	$—	$ —	$—	$24
Commingled funds	758	79	—	—	819	898
Debt securities	466	—	436	—	—	436
Equity securities	401	697	—	—	—	697
Total	$1,649	$800	$436	$ —	$819	$2,055

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $141 million of equity investments in unconsolidated subsidiaries and $121 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$29	$29	$—	$ —	$—	$29
Commingled funds	701	223	—	—	659	882
Debt securities	438	—	441	—	—	441
Equity securities	423	791	—	—	—	791
Total	$1,591	$1,043	$441	$ —	$659	$2,143

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $114 million of rabbi trust assets and miscellaneous investments.

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For the years ended Dec. 31, 2018 and 2017, there were no Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2018:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ 10	$ 107	$ 211	$ 108	$ 436

Rabbi Trusts

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

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 16	$ 16	$ —	$ —	$ 16
Mutual funds	52	51	—	—	51
Total	$ 68	$ 67	$ —	$ —	$ 67

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 12	$ 12	$ —	$ —	$ 12
Mutual funds	47	50	—	—	50
Total	$ 59	$ 62	$ —	$ —	$ 62

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

Derivative Fair Value Measurements

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

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2018, accumulated other comprehensive losses related to interest rate derivatives included $3 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

As of Dec 31, 2018, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $300 million. These interest rate derivatives were designated as hedges, and as such, changes in fair value are recorded to other comprehensive income.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within

guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.
Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.
As of Dec. 31, 2018, Xcel Energy had no vehicle fuel contracts designated as cash flow hedges. Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2018 and 2017.
As of Dec. 31, 2018, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.
Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.
Gross notional amounts of commodity forwards, options and FTRs as of Dec. 31:

(Amounts in Millions) [(a)] [(b)]	2018	2017
MWh of electricity	87	68
MMBtu of natural gas	92	37

(a) Amounts are not reflective of net positions in the underlying commodities.
(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.
Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.
Xcel Energy’s utility subsidiaries’ most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

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As of Dec. 31, 2018, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $96 million or 43% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Three of the 10 most significant counterparties, comprising $20 million or 9% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $12 million or 5% of this credit exposure, had credit quality less than investment grade, based on Xcel Energy's internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2018	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(58)	$(51)	$(55)
After-tax net unrealized losses related to derivatives accounted for as hedges	(5)	—	—
After-tax net realized losses on derivative transactions reclassified into earnings	3	3	4
Adoption of ASU. 2018-02 [(a)]	—	(10)	—
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$(60)	$(58)	$(51)

(a) In 2017, Xcel Energy implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2018		
Derivatives designated as cash flow hedges		
Interest rate	$ (7)	$ —
Total	$ (7)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 1
Natural gas commodity	—	10
Total	$ —	$ 11
Year Ended Dec. 31, 2017		
Other derivative instruments		
Electric commodity	$ —	$ 10
Natural gas commodity	—	(13)
Total	$ —	$ (3)
Year Ended Dec. 31, 2016		
Other derivative instruments		
Electric commodity	$ —	$ 17
Natural gas commodity	—	1
Total	$ —	$ 18

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [(a)]	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 14 [(b)]
Electric commodity	—	(1) [(c)]	—
Natural gas commodity	—	(6) [(d)]	(4) [(d)]
Total	$ —	$ (7)	$ 10
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	$ 5 [(a)]	$ —	$ —
Total	$ 5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10 [(b)]
Electric commodity	—	(15) [(c)]	—
Natural gas commodity	—	3 [(d)]	(6) [(d)]
Total	$ —	$ (12)	$ 4
Year Ended Dec. 31, 2016			
Derivatives designated as cash flow hedges			
Interest rate	$ 6 [(a)]	$ —	$ —
Total	$ 6	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 [(b)]
Electric commodity	—	(8) [(c)]	—
Natural gas commodity	—	15 [(d)]	(8) [(d)]
Total	$ —	$ 7	$ (6)

(a) Amounts recorded to interest charges.

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

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

(d) Amounts for the year ended Dec. 31, 2018 included $1 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such gains and losses for the years ended Dec. 31, 2017 and 2016 were immaterial. Remaining settlement losses for the years ended Dec. 31, 2018, 2017 and 2016 related to natural gas operations and were recorded to cost of natural gas sold and transported.

These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2018, 2017 and 2016.

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Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2018 and 2017, there were no derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2018 and 2017.

Recurring Fair Value Measurements — Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis:

(Millions of Dollars)	Dec. 31, 2018 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Dec. 31, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Commodity trading	$4	$ 92	$ 2	$ 98	$ (44)	$ 54	$2	$ 22	$ —	$ 24	$ (15)	$ 9
Electric commodity	—	—	25	25	—	25	—	—	32	32	(2)	30
Natural gas commodity	—	4	—	4	—	4	—	—	—	—	—	—
Total current derivative assets	$4	$ 96	$ 27	$ 127	$ (44)	83	$2	$ 22	$ 32	$ 56	$ (17)	39
PPAs (b)						4						5
Current derivative instruments						$ 87						$ 44
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$—	$ 27	$ 5	$ 32	$ (14)	$ 18	$—	$ 31	$ 5	$ 36	$ (7)	$ 29
Total noncurrent derivative assets	$—	$ 27	$ 5	$ 32	$ (14)	18	$—	$ 31	$ 5	$ 36	$ (7)	29
PPAs (b)						16						19
Noncurrent derivative instruments						$ 34						$ 48

(Millions of Dollars)	Dec. 31, 2018 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Dec. 31, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$—	$ 7	$ —	$ 7	$—	$7	$—	$ —	$ —	$ —	$—	$—
Other derivative instruments:												
Commodity trading	4	88	2	94	(60)	34	2	18	—	20	(15)	5
Electric commodity	—	—	—	—	—	—	—	—	2	2	(2)	—
Natural gas commodity	—	—	—	—	—	—	—	1	—	1	—	1
Total current derivative liabilities	$4	$ 95	$ 2	$ 101	$ (60)	41	$2	$ 19	$ 2	$ 23	$ (17)	6
PPAs (b)						20						23
Current derivative instruments						$61						$29
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$—	$ 18	$ 1	$ 19	$ 17	$36	$—	$ 24	$ —	$ 24	$ (10)	$14
Total noncurrent derivative liabilities	$—	$ 18	$ 1	$ 19	$ 17	36	$—	$ 24	$ —	$ 24	$ (10)	14

PPAs [b]	93	112
Noncurrent derivative instruments	$129	$126

(a) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2018 and 2017. At Dec. 31, 2018 and 2017, derivative assets and liabilities include $32 million and $0 million of obligations to return cash collateral, respectively. At Dec. 31, 2018 and 2017, derivative assets and liabilities include rights to reclaim cash collateral of $15 million and $3 million, respectively. Counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

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Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Year Ended Dec. 31 2018	2017	2016
Balance at Jan. 1	$35	$17	$18
Purchases	59	82	35
Settlements	(59)	(97)	(89)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(1)	5	—
Net (losses) gains recognized as regulatory assets and liabilities	(5)	28	53
Balance at Dec. 31	$29	$35	$17

(a) Amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2016 - 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

(Millions of Dollars)	2018 Carrying Amount	2018 Fair Value	2017 Carrying Amount	2017 Fair Value
Long-term debt, including current portion	$16,209	$16,755	$14,977	$16,531

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2018 and 2017, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 were $33 million and $37 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2018 and $5 million in 2017.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy's consolidated operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota and NSP-Wisconsin discontinued subsidizing health care benefits for non-bargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued subsidizing health care benefits for nonbargaining employees of the former NCE who retired after June 30, 2003.
- Xcel Energy discontinued health care benefits for SPS bargaining employees hired after Jan. 1, 2012.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2018 were below the assumed level of 6.87%;
- Investment returns in 2017 were above the assumed level of 6.87%;
- Investment returns in 2016 were below the assumed level of 6.87%; and,
- In 2019, Xcel Energy’s expected investment-return assumption is 6.87%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy’s return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy’s ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan’s funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

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Plan Assets

The following presents, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2018 [a] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2017 [a] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$137	$—	$ —	$ —	$137	$196	$—	$ —	$ —	$196
Commingled funds:	914	—	—	987	1,901	1,054	—	—	1,075	2,129
Debt securities:	—	621	—	—	621	—	673	—	—	673
Equity securities:	106	—	—	—	106	114	—	—	—	114
Other	2	5	—	(30)	(23)	(29)	4	—	1	(24)
Total	$1,159	$626	$ —	$ 957	$2,742	$1,335	$677	$ —	$ 1,076	$3,088

[a] See Note 10 for further information regarding fair value measurement inputs and methods.

The following presents, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

(Millions of Dollars)	Dec. 31, 2018 [a] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2017 [a] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$19	$—	$ —	$ —	$19	$29	$—	$ —	$ —	$29
Insurance contracts	—	45	—	—	45	—	50	—	—	50
Commingled funds	133	—	—	40	173	148	—	—	—	148
Debt securities	—	179	—	—	179	—	198	—	—	198
Equity securities	—	—	—	—	—	35	—	—	—	35
Other	—	1	—	—	1	—	1	—	—	1
Total	$152	$225	$ —	$ 40	$417	$212	$249	$ —	$ —	$461

[a] See Note 10 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2018 and 2017.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

(Millions of Dollars)	Pension Benefits 2018	2017	Postretirement Benefits 2018	2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$3,828	$3,682	$621	$603
Service cost	94	94	2	2
Interest cost	133	147	22	24
Plan amendments	—	(13)	—	—
Actuarial (gain) loss	(224)	259	(62)	33
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments [a]	(354)	(341)	(50)	(50)
Obligation at Dec. 31	$3,477	$3,828	$542	$621
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$3,088	$2,856	$461	$442
Actual return on plan assets	(142)	411	(13)	41
Employer contributions	150	162	11	20
Plan participants' contributions	—	—	8	8
Benefit payments	(354)	(341)	(50)	(50)
Fair value of plan assets at Dec. 31	$2,742	$3,088	$417	$461

Funded status of plans at Dec. 31	$(735)	$(740)	$(125)	$(160)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current liabilities	$—	$—	$(7)	$(3)
Noncurrent liabilities	(735)	(740)	(118)	(157)
Net amounts recognized	$(735)	$(740)	$(125)	$(160)

(a) Includes approximately $198 million in 2018 and $174 million in 2017 of lump-sum benefit payments used in the determination of a settlement charge.

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	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31 %	3.63 %	4.32 %	3.62 %
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50 %	7.00 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.35 %	5.50 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $3,275 million and $3,612 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2018	2017	2016	2018	2017	2016
Service cost	$94	$94	$92	$2	$2	$2
Interest cost	133	147	160	22	24	26
Expected return on plan assets	(209)	(209)	(210)	(26)	(25)	(25)
Amortization of prior service credit	(5)	(2)	(2)	(11)	(11)	(11)
Amortization of net loss	111	107	97	8	7	4
Settlement charge [(a)]	91	81	—	—	—	—
Net periodic pension cost (credit)	215	218	137	(5)	(3)	(4)
Costs not recognized due to effects of regulation	(75)	(79)	(15)	2	—	—
Net benefit cost (credit) recognized for financial reporting	$140	$139	$122	$(3)	$(3)	$(4)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.63 %	4.13 %	4.66 %	3.62 %	4.13 %	4.65 %
Expected average long-term increase in compensation level	3.75	3.75	4.00	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	5.30	5.80	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, Xcel Energy recorded a total pension settlement charge of $91 million in 2018 and $81 million in 2017, the majority of which was not recognized due to the effects of regulation. A total of $11 million and $8 million was recorded in the consolidated statements of income in 2018 and 2017, respectively.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$1,633	$1,709	$116	$147
Prior service credit	(20)	(25)	(33)	(44)
Total	$1,613	$1,684	$83	$103
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$94	$100	$—	$—

Noncurrent regulatory assets	1,446	1,511	89	107
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(10)	(10)
Deferred income taxes	19	19	1	2
Net-of-tax accumulated other comprehensive income	54	54	4	5
Total	$ 1,613	$ 1,684	$ 83	$ 103
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

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Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2016 - 2019 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and,
- $125 million in 2016.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- Expects to contribute approximately $11 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and,
- $18 million during 2016.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Domestic and international equity securities	36 %	36 %	18 %	24 %
Long-duration fixed income securities	30	27	—	—
Short-to-intermediate fixed income securities	17	20	70	60
Alternative investments	15	15	8	9
Cash	2	2	4	7
Total	100 %	100 %	100 %	100 %

Plan Amendments — The Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) were amended in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans. In 2016, the Xcel Energy Pension Plan was amended to change the discount rate basis for lump-sum conversion to annuity participants and annuity conversion to lump-sum participants. Annual credits contributed to the PSCo Bargaining Plan retirement spending account also increased.

In 2018 and 2017, there were no plan amendments made which affected the postretirement benefit obligation.

Projected Benefit Payments

Xcel Energy’s projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2019	$ 281	$ 45	$ 2	$ 43
2020	260	45	2	43
2021	259	45	2	43
2022	260	44	2	42
2023	259	43	2	41
2024-2028	1,238	197	13	184

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $38 million in 2018, $37 million in 2017 and $36 million in 2016.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves 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 when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy’s financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

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

In the fourth quarter of 2018, four cases were settled. Two cases remain active which include an MDL matter consisting of a Colorado class (Breckenridge) and a Wisconsin class (Arandell Corp.).

Breckenridge/Colorado — Case has been remanded to the MDL panel, and is expected to be referred back to the U.S. District Court in Colorado. Xcel Energy has concluded that a loss is remote.

Arandell Corp. — In November 2017, the U.S. District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs’ motions for class certification and remand back to originating courts were denied in March 2017.

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Plaintiffs have asked the lower court to remand the cases back to the court where the actions were originally filed anticipating class certification. A hearing date has not been set. Xcel Energy has concluded that a loss is remote.
Line Extension Disputes — In December 2015, the DRC filed a lawsuit seeking monetary damages in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements. The dispute involves claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so.
This claim is substantially similar to the arguments previously raised by DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. DRC subsequently filed an appeal to the Colorado Court of Appeals with its opening brief in January 2019 and PSCo filed its answer brief in February 2019. It is uncertain when a decision will be rendered.
PSCo has concluded that a loss is remote with respect to both of these matters as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. If a loss were sustained, PSCo believes it would be allowed to recover costs through traditional regulatory mechanisms. Amount or range in dispute is presently unknown and no accrual has been recorded for this matter.
Rate Matters
NSP-Minnesota — Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.
In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota has notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA.
The insurance providers continued their litigation against GE and the case went to trial. In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.
In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals.
NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.
MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%.

In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.
In October 2018, the FERC issued a NETO base ROE order that addressed the D.C. Circuit's actions on Opinion No. 531. Under a new proposed two step ROE approach, the FERC has indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the DCF, CAPM, and Expected Earnings models. The FERC proposes that if necessary, it would then set a new ROE by

averaging the results of these models plus a Risk Premium model.
With respect to the MISO TOs, the FERC subsequently made preliminary determinations in a November 2018 order that the MISO base ROE in effect for the first complaint period (12.38%) was outside the range of reasonableness, and should be reduced. The FERC indicated its preliminary analysis using the new ROE approach resulted in a base ROE of 10.28% for the first compliant period, compared to the previously ordered base ROE of 10.32%. A procedural schedule has been set for the first half of 2019, with the FERC expected to act no earlier than the second half of 2019. NSP-Minnesota has recognized a current refund liability consistent with its best estimate of the final ROE.
SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP’s request to recover these previously unbilled charges. SPP subsequently billed SPS approximately $13 million for these charges.
In July 2018, SPS’ appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. Assessment of these charges (from 2008 - 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.
In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC has granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS’ complaint results in additional charges or refunds, it will seek to recover or refund the differential in future rate proceedings.
Environmental
New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.
Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.’s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.’s subsidiaries are alleged to have sent wastes to that site.

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MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation and restoration activities are anticipated to be completed in 2019 and groundwater treatment activities will continue for many years.

Current cost estimate for remediation of the entire site is approximately $192 million, of which approximately $165 million has been spent. As of Dec. 31, 2018 and 2017, NSP-Wisconsin recorded a total liability of $27 million and $30 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a 10-year period and to apply a 3% carrying cost to the unamortized regulatory asset.

MGP, Landfill or Disposal Sites — Xcel Energy is currently investigating or remediating twelve MGP, landfill or other disposal sites across its service territories, in addition to the Ashland MGP Site, and these activities will continue through at least 2019. Xcel Energy accrued $9 million as of Dec. 31, 2018 and $19 million as of Dec. 31, 2017 for these sites. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of the costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published the CCR Rule. Litigation was brought challenging the rule in the D.C. Circuit.

Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Xcel Energy has identified at least two sites in Colorado where SSLs exist in the groundwater near landfills and/or impoundments. Xcel Energy has completed removal of CCR from these impoundments and plans to close these landfills. By the end of 2019, only nine of Xcel Energy’s regulated ash units are expected to be in operation. Xcel Energy is conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments.

Until Xcel Energy completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows. In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. Litigation is ongoing regarding the deadline for closing or retrofitting these impoundments. The decision will require Xcel Energy to expedite closure of one impoundment in Minnesota (see ARO removal costs below) and will require construction of a new impoundment, which is estimated to cost $6 million.

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as “WOTUS”. The Rule has been subject to significant litigation and is currently stayed in a portion of the country. Xcel Energy cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, Xcel Energy estimates that ELG compliance will cost approximately $12 million to complete. The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely cost for complying with impingement and entrainment requirements is approximately $40 million, to be incurred between 2019 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to approximately $200 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, NO_X and PM emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress.

The requirements of the first regional haze plans developed by Minnesota and Colorado have been approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. It is not known when the EPA will make a final decision on this proposal.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

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In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with an exception. The EPA issued final designations which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. Xcel Energy cannot evaluate the impacts until the final designation is made and any required state plans are developed. Xcel Energy believes that should SO_2 control systems be required for a plant, compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.1 billion for 2018 and 2017.

Xcel Energy's AROs were as follows:

	Dec. 31, 2018					
(Millions of Dollars)	Jan. 1, 2018	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2018
Electric						
Nuclear	$1,874	$ —	$ —	$ 94	$ —	$1,968
Steam, hydro, and other production	192	—	(14)	8	(9)	177
Wind	96	12	—	4	7	119
Distribution	21	—	—	1	20	42
Miscellaneous	5	—	—	—	2	7
Natural gas						
Transmission and distribution	282	—	—	13	(46)	249
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	—	1	—	—	—	1
Total liability	$2,475	$ 13	$ (14)	$ 120	$ (26)	$2,568

(a) Amounts incurred related to the PSCo Rush Creek wind farm and Nicollet Projects community solar gardens, which were placed in service in 2018.

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

	Dec. 31, 2017					
(Millions of Dollars)	Jan. 1, 2017	Amounts Incurred	Amounts Settled (a)	Accretion	Cash Flow Revisions (b)	Dec. 31,

						2017
Electric						
Nuclear	$2,249	$ —	$ —	$ 114	$ (489)	$1,874
Steam, hydro, and other production	205	1	(29)	9	6	192
Wind	92	—	—	4	—	96
Distribution	20	—	—	1	—	21
Miscellaneous	5	—	—	—	—	5
Natural gas						
Transmission and distribution	205	—	—	8	69	282
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	2	—	(1)	—	—	1
Total liability	$2,782	$ 1	$ (30)	$ 136	$ (414)	$2,475

(a) Amounts settled related to asbestos abatement, closure of ash containment facilities, and removal and disposal of storage tanks and other above ground equipment.

(b) In 2017, AROs were revised for changes in timing and estimates of cash flows. Nuclear AROs decreased due to updated assumptions. Changes in gas transmission and distribution AROs were primarily related to increased labor costs.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2018. Therefore, an ARO was not recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of its utility subsidiaries that are recovered currently in rates. Removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. The utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accumulated balances by entity at Dec. 31:

(Millions of Dollars)	2018	2017
NSP-Minnesota	$485	$442
PSCo	344	346
SPS	188	197
NSP-Wisconsin	158	146
Total Xcel Energy	$1,175	$1,131

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $14.1 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.6 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government.

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NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of approximately $18 million for business interruption insurance and $39 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 44 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligation for decommissioning is expected to be funded 100% by the external decommissioning trust fund. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30% Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota has accumulated $2.1 billion of assets held in external decommissioning trusts in 2018. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements (ARO).

	Regulatory Basis	
(Millions of Dollars)	2018	2017
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$3,012	$3,012
Effect of escalating costs	539	396
Estimated decommissioning cost obligation (in current dollars)	3,551	3,408
Effect of escalating costs to payment date	7,654	7,797
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 3.33% and 2.80% for 2018 and 2017, respectively)	(6,911)	(6,398)
Discounted decommissioning cost obligation	$4,294	$4,807

Assets held in external decommissioning trust	$2,055	$2,143
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,239	2,664

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2018	2017
Discounted decommissioning cost obligation - regulated basis	$4,294	$4,807
Differences in discount rate and market risk premium	(1,447)	(1,403)
O&M costs not included for GAAP	(879)	(1,041)
ARO differences between 2017 and 2014 cost studies	—	(489)
Nuclear production decommissioning ARO - GAAP	$1,968	$1,874

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2018	2017	2016
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 20	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2018, 2017 and 2016 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2018, 2017 and 2016. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC.

Leases — Xcel Energy has three leases accounted for as capital leases. The assets and liabilities of a capital lease are recorded at the lower of fair market value of the leased asset or the present value of future lease payments and are amortized over the term of the contract.

WYCO is a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

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PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. Xcel Energy Inc. eliminates 50% of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.
PSCo records amortization for its capital lease assets as electric fuel and purchased power and cost of natural gas sold and transported on the consolidated statements of income.
Property held under capital leases:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Gas storage facilities	$201	$201
Gas pipeline	21	21
Property held under capital leases	222	222
Accumulated depreciation	(77)	(71)
Total property held under capital leases, net	$145	$151

Remaining leases, primarily for real estate and certain natural gas generating facilities operated under PPAs, as well as railcars, aircraft and other equipment, are accounted for as operating leases.
Total expenses (including capacity payments) under operating lease obligations for Xcel Energy and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Total expense	$248	$246	$255
Capacity payments	210	210	216

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.
Future commitments under operating and capital leases:

(Millions of Dollars)	Operating Leases	PPA [a] [b] Operating Leases	Total Operating Leases	Capital Leases
2019	$ 32	$ 207	$ 239	$ 14
2020	26	208	234	14
2021	25	210	235	14
2022	24	197	221	12
2023	22	186	208	12
Thereafter	154	883	1,037	220
Total minimum obligation				286
Interest component of obligation				(201)
Present value of minimum obligation				$ 85 [c]

(a) Amounts do not include PPAs accounted for as executory contracts.
(b) PPA operating leases contractually expire through 2034.
(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

Non-Lease PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements, meet operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts contain minimum energy purchase commitments.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $131 million, $168 million and $191 million in 2018, 2017 and 2016, respectively.

At Dec. 31, 2018, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [(a)]
2019	$ 86	$99
2020	70	109
2021	78	157
2022	77	173
2023	79	177
Thereafter	125	328
Total	$ 515	$1,043

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2019 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2018:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2019	$461	$ 127	$416	$ 268
2020	260	51	263	255
2021	149	99	254	245
2022	109	79	114	234
2023	61	99	60	170
Thereafter	108	337	—	923
Total	$1,148	$ 792	$1,107	$ 2,095

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities.

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Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy's utility subsidiaries had approximately 3,770 MW and 3,537 MW of capacity under long-term PPAs at Dec. 31, 2018 and 2017, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs. SPS has determined that TUCO is a VIE. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership. Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Current assets	$ 5	$ 6
Property, plant and equipment, net	42	46
Other noncurrent assets	1	1
Total assets	$ 48	$ 53
Current liabilities	$ 7	$ 9
Mortgages and other long-term debt payable	26	26
Other noncurrent liabilities	—	1
Total liabilities	$ 33	$ 36

Other

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with IBM for information technology services. Contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50% of the contract value for early termination. Xcel Energy capitalized or expensed $81 million, $98 million and $119 million associated with the IBM contract in 2018, 2017 and 2016, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. Contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $46 million, $16 million and $35 million associated with the Accenture contract in 2018, 2017 and 2016, respectively.

Committed minimum payments under these obligations:

(Millions of Dollars)

	IBM Agreement	Accenture Agreement
2019	$ 30	$ 11
2020	16	11
2021	16	—
2022	7	—
2023	—	—
Thereafter	—	—

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries enter into contractual guarantees in limited circumstances. Xcel Energy Inc. may guarantee the subsidiaries' obligations in the event they fail to perform and may provide guarantees in certain indemnification agreements. Xcel Energy Inc.'s guarantees from the subsidiaries are not individually material with maximum potential liability totaling $6 million as of Dec. 31, 2018. Payment for these guarantees is considered remote.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss), net of tax, for the years ended Dec. 31:

(Millions of Dollars)	2018 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(58)	$ (67)	$(125)
Other comprehensive loss before reclassifications (net of taxes of $(2) and $(2), respectively)	(5)	(6)	(11)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $3, respectively)	—	9 (b)	9
Net current period other comprehensive income (loss)	(2)	3	1
Accumulated other comprehensive loss at Dec. 31	$(60)	$ (64)	$(124)

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(Millions of Dollars)	2017 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(51)	$ (59)	$(110)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(2), respectively)	—	(3)	(3)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $0, respectively)	3 [(a)]	—	3
Amortization of net actuarial loss (net of taxes of $0 and $5, respectively)	—	7 [(b)]	$7
Net current period other comprehensive income	3	4	7
Adoption of ASU No. 2018-02 [(c)]	(10)	(12)	(22)
Accumulated other comprehensive loss at Dec. 31	$(58)	$ (67)	$(125)

(a) Included in interest charges.

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

(c) In 2017, Xcel Energy implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

14. Segments and Related Information

Regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- Regulated Electric - The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- Regulated Natural Gas - The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- All Other - Operating segments with revenues below the necessary quantitative thresholds are included in this category. Those segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $141 million and $140 million as of Dec. 31, 2018 and 2017, respectively, included in the natural gas utility and all other segments.

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

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

Xcel Energy's segment information:

(Millions of Dollars)	2018	2017	2016
Regulated Electric			
Operating revenues from external customers	$9,719	$9,676	$9,500
Intersegment revenue	1	2	1
Total revenues	$9,720	$9,678	$9,501
Depreciation and amortization	1,421	1,298	1,136
Interest charges and financing costs	449	449	450
Income tax expense	187	528	567
Net income	1,177	1,066	1,067
Regulated Natural Gas			
Operating revenues from external customers	$1,739	$1,650	$1,531
Intersegment revenue	2	1	1
Total revenues	$1,741	$1,651	$1,532
Depreciation and amortization	212	174	160
Interest charges and financing costs	61	57	54
Income tax expense	28	23	76
Net income	187	182	124
All Other			
Total operating revenue	$79	$78	$76
Depreciation and amortization	9	7	7
Interest charges and financing costs	142	122	116
Income tax (benefit)	(34)	(9)	(62)
Net (loss)	(103)	(100)	(68)

(Millions of Dollars)	2018	2017	2016
Consolidated Total			
Total revenue	$11,540	$11,407	$11,109
Reconciling eliminations	(3)	(3)	(2)
Consolidated total revenue	$11,537	$11,404	$11,107
Depreciation and amortization	1,642	1,479	1,303
Interest charges and financing costs	652	628	620
Income tax expense	181	542	581
Net income	1,261	1,148	1,123

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15. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$2,951	$2,658	$3,048	$2,880
Operating income [(a)]	480	450	696	339
Net income	291	265	491	214
EPS total — basic	$0.57	$0.52	$0.96	$0.42
EPS total — diluted	0.57	0.52	0.96	0.42
Cash dividends declared per common share	0.38	0.38	0.38	0.38

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$2,946	$2,645	$3,017	$2,796
Operating income [(a)]	492	466	824	440
Net income	239	227	492	189
EPS total — basic	$0.47	$0.45	$0.97	$0.37
EPS total — diluted	0.47	0.45	0.97	0.37
Cash dividends declared per common share	0.36	0.36	0.36	0.36

(a) In 2018, Xcel Energy implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of Dec. 31, 2018, based on an evaluation carried out under the supervision and with the participation of Xcel Energy’s management, including the chief executive officer and chief financial officer, of the effectiveness of its disclosure controls and the procedures, the chief executive officer and chief financial officer have concluded that Xcel Energy’s disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy’s internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy’s internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting.

Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2018 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.’s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.’s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

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PART IV

Item 15 — Exhibits, Financial Statement Schedules

1 Consolidated Financial Statements
Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2018.
Report of Independent Registered Public Accounting Firm — Financial Statements
Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
Consolidated Statements of Income — For the three years ended Dec. 31, 2018, 2017, and 2016.
Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2018, 2017, and 2016.
Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2018, 2017, and 2016.
Consolidated Balance Sheets — As of Dec. 31, 2018 and 2017.
Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2018, 2017, and 2016.

2 Schedule I — Condensed Financial Information of Registrant.
Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2018, 2017 and 2016.

3 Exhibits
* Indicates incorporation by reference
+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated May 16, 2012	001-03034	3.01
3.02*	Bylaws of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated Feb. 17, 2016	001-03034	3.01
4.01*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	001-03034	4.01
4.02*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	001-03034	4.01
4.03*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.01
4.04*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.03
4.05*	Supplemental Indenture No. 5, dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated May 10, 2010	001-03034	4.01
4.06*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	001-03034	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo	Xcel Energy Inc. Form 8-K dated June 1, 2015	001-03034	4.01

	Bank, National Association, as Trustee			
4.08*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	001-03034	4.02
4.09*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	001-03034	4.01
4.10*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	001-03034	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.08*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A

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10.09*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.10*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Schedule 14A
10.11*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.12*+	First Amendment to Exhibit 10.11 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.13*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.14*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.15*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.16*+	First Amendment to Exhibit 10.09 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.21
10.17*+	Second Amendment to Exhibit 10.11 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.18*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.23
10.19*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2015	001-03034	Schedule 14A
10.20*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.21*	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy	Xcel Energy Inc. Form 8-K dated	001-03034	10.03

	Inc. 2015 Omnibus Incentive Plan	May 20, 2015		
10.22*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.28
10.23*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.29
10.24*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.25*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 among Xcel Energy Inc., as borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd. , as Document Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.01
10.26*+	Third Amendment to Exhibit 10.11 dated Sept. 30, 2016	Xcel Energy inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.27*+	Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2016	001-03034	10.27
10.28*+	Fourth Amendment to Exhibit 10.11 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.29*	364-Day Term Loan Agreement dated Dec. 5, 2017 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent	Xcel Energy Inc. Form 8-K dated Dec. 5, 2017	001-03034	99.01
10.30*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.31*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.32*	Forward Sale Agreement, dated Nov. 7, 2018, between Xcel Energy Inc. and Morgan Stanley &Co., LLC	Xcel Energy Inc. Form 8-K dated Nov. 7, 2018	001-03034	10.01
10.33*	Amended and Restated 364-Day Term Loan Agreement dated as of Dec. 4, 2018 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and MUFG Bank, Ltd. as Administrative Agent.	Xcel Energy Inc. Form 8-K dated Dec. 4, 2018	001-03034	99.01

10.34+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan		
10.35+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan		
10.36+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan		

NSP-Minnesota

4.11*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-030344(b)(3)
4.12*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-030344.11
4.13*	Supplemental Trust (Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-030344.12

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4.14*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.15*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(7)
4.16*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.63
4.17*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	001-31387	4.01
4.18*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	001-31387	4.01
4.19*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	001-31387	4.01
4.20*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	001-31387	4.01
4.21*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due Aug. 15, 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	001-31387	4.01
4.22*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	001-31387	4.01
4.23*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	001-31387	4.01
4.24*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	001-31387	4.01
4.25*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due	NSP-Minnesota Form 8-K dated Aug. 11, 2015	001-31387	4.01

	Aug. 15, 2045			
4.26*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due May 31, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.27*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	001-31387	4.01
10.37*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.38*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.02
NSP-Wisconsin				
4.28*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(c)(3)
4.29*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	001-03140	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991	Xcel Energy Inc Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.05
4.31*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	001-03140	4.01
4.32*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	001-03140	4.01
4.33*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due June 1, 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	001-03140	4.01
4.34*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million in aggregate principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	001-03140	4.01
4.35*	Supplemental Indenture dated as of Sept. 1, 2018 between Northern States Power Company and U.S. Bank National Association, as successor Trustee, creating 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin to Form 8-K dated Sept. 12, 2018	001-03034	4.01

10.39*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01

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10.40*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016		99.05
PSCo				
4.36*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(d)(3)
4.37*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 14, 1999 between PSCo and the Bank of New York	PSCo Form 8-K dated July 13, 1999	001-03280	4.1 4.2
4.38*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	001-03280	4.01
4.39*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series No. 18 due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038	PSCo Form 8-K dated Aug. 6, 2008	001-03280	4.01
4.40*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125% First Mortgage Bonds, Series No. 20 due 2019	PSCo Form 8-K dated May 28, 2009	001-03280	4.01
4.41*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.20% First Mortgage Bonds, Series No. 21 due 2020	PSCo Form 8-K dated Nov. 8, 2010	001-03280	4.01
4.42*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series No. 22 due 2041	PSCo Form 8-K dated Aug. 9, 2011	001-03280	4.01
4.43*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series No. 24 due 2042	PSCo Form 8-K dated Sept. 11, 2012	001-03280	4.01
4.44*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series No. 25 due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series No. 26 due 2043	PSCo Form 8-K dated March 26, 2013	001-03280	4.01
4.45*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series No. 27 due 2044	PSCo Form 8-K dated March 10, 2014	001-03280	4.01
4.46*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series No. 28 due 2025	PSCo Form 8-K dated May 12, 2015	001-03280	4.01

4.47*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series No. 29 due 2046	PSCo Form 8-K dated June 13, 2016	001-03280	4.01
4.48*	Supplemental Indenture No. 27 dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series No. 30 due 2047	PSCo Form 8-K dated June 19, 2017	001-03280	4.01
4.49*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series No. 31 due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series No. 32 due 2048	PSCo Form 8-K dated June 21, 2018	001-03280	4.01
10.41*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	001-03034	99.02
10.42*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.03
SPS				
4.50*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.51*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.04
4.52*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.53*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.01
4.54*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series No. 1 due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.55*	Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and the Bank of New York Mellon Trust Company, N.A., as successor Trustee	SPS Form 8-K dated June 2, 2014	001-03789	4.03
4.56*	Supplemental Indenture No. 3 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series No. 3 due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.57*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series No. 4 due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02

4.58*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series No. 5 due 2047	SPS Form 8-K dated Aug 9. 2017	001-037894.02
4.59*	Supplemental Indenture No. 6 dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating 4.40% First Mortgage Bonds, Series No. 6 due 2048	SPS Form 8-K dated Nov. 5, 2018	001-037894.02
10.43*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-0303499.04

Xcel Energy Inc.

21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm
24.01	Powers of Attorney
31.01	Principal Executive Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.02	Principal Financial Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	The following materials from Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders’ Equity, (vi) Notes to Consolidated Financial Statements, (vii) document and entity information, (viii) Schedule I, and (ix) Schedule II.

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SCHEDULE I
XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2018	2017	2016
Income			
Equity earnings of subsidiaries	$ 1,393	$ 1,263	$ 1,199
Total income	1,393	1,263	1,199
Expenses and other deductions			
Operating expenses	24	30	22
Other income	(1)	(6)	(3)
Interest charges and financing costs	149	128	116
Total expenses and other deductions	172	152	135
Income before income taxes	1,221	1,111	1,064
Income tax benefit	(40)	(37)	(59)
Net income	$ 1,261	$ 1,148	$ 1,123
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $1, $3 and $(3) respectively	$ 3	$ 4	$ (4)
Derivative instruments, net of tax of $(1), $2 and $2, respectively	(2)	3	4
Other comprehensive income (loss)	1	7	—
Comprehensive income	$ 1,262	$ 1,155	$ 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 Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net cash provided by operating activities	$1,210	$1,208	$817
Investing activities			
Capital contributions to subsidiaries	(809)	(849)	(414)
Investments in the utility money pool	(2,578)	(1,258)	(1,880)
Return of investments in the utility money pool	2,493	1,173	1,880
Net cash used in investing activities	(894)	(934)	(414)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	(295)	715	(516)
Proceeds from issuance of long-term debt	492	—	1,539
Repayment of long-term debt	—	(250)	(704)
Proceeds from issuance of common stock	230	—	—
Repurchase of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other	(12)	(14)	(9)
Net cash (used in) provided by financing activities	(316)	(273)	(403)
Net change in cash and cash equivalents	—	1	—
Cash and cash equivalents at beginning of period	1	—	—
Cash and cash equivalents at end of period	$1	$1	$—

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2018	2017
Assets		
Cash and cash equivalents	$1	$1
Accounts receivable from subsidiaries	309	302
Other current assets	1	1
Total current assets	311	304
Investment in subsidiaries	15,965	14,932
Other assets	44	103
Total other assets	16,009	15,035
Total assets	$16,320	$15,339
Liabilities and Equity		
Current portion of long-term debt	$—	$—
Dividends payable	195	183
Short-term debt	488	783
Other current liabilities	10	11
Total current liabilities	693	977
Other liabilities	32	29
Total other liabilities	32	29
Commitments and contingencies		
Capitalization		

Long-term debt	3,373	2,878
Common stockholders’ equity	12,222	11,455
Total capitalization	15,595	14,333
Total liabilities and equity	$16,320	$15,339

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy’s consolidated statements of common stockholders’ equity and other comprehensive income in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.’s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.’s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.’s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.’s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

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Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2018 and 2017, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2018:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases [a]	Xcel Energy Inc.	$ 11.0	$ —	[d]
Guarantee of loan for Hiawatha Collegiate High School [b]	Xcel Energy Inc.	1.0	—	[d]
Total guarantees issued		12.0	$ —	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries[c]	Xcel Energy Inc.	$ 51.1	[f]	[e]

[a] The terms of this guarantee expires in 2021 and 2023 when the associated leases expire.

[b] The term of this guarantee expires the earlier of 2024 or full repayment of the loan.

[c] The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

[d] Nonperformance and/or nonpayment.

[e] Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

[f] Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31:

(Millions of Dollars)	2018 Accounts Receivable	2018 Accounts Payable	2017 Accounts Receivable	2017 Accounts Payable
NSP-Minnesota	$ 117	$ —	$ 68	$ —
NSP-Wisconsin	3	—	13	—
PSCo	29	—	69	—
SPS	39	—	26	—
Xcel Energy Services Inc.	96	—	95	—
Xcel Energy Ventures Inc.	13	—	14	—
Other subsidiaries of Xcel Energy Inc.	12	—	17	—
	$ 309	$ —	$ 302	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,097 million, $1,063 million and $923 million for the years ended Dec. 31, 2018, 2017 and 2016, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — FERC approval was received to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018
Loan outstanding at period end	$ —
Average loan outstanding	59
Maximum loan outstanding	172
Weighted average interest rate, computed on a daily basis	2.22 %
Weighted average interest rate at end of period	N/A
Money pool interest income	$ 0.3

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Loan outstanding at period end	$—	$85	$—
Average loan outstanding	71	38	66
Maximum loan outstanding	243	226	211
Weighted average interest rate, computed on a daily basis	1.95 %	1.13 %	0.69 %
Weighted average interest rate at end of period	N/A	1.18	N/A
Money pool interest income	$1.4	$0.4	$0.5

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES VALUATION AND QUALIFYING ACCOUNTS YEARS ENDED DEC. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2018	2017	2016	2018	2017	2016
Balance at Jan. 1	$52	$51	$52	$77	$58	$28
Additions Charged to Costs and Expenses	42	39	39	7	9	3
Additions Charged to Other Accounts	11	10	11	— (a)	22 (a)	35 (a)
Deductions from Reserves	(50)	(48)	(51)	(5) (b)	(12) (b)	(8) (b)
Balance at Dec. 31	$55	$52	$51	$79	$77	$58

(a) The 2016 - 2017 changes are the accrual of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability; the 2017 change includes $14 million expense related to the revaluation of federal benefit as a result of the TCJA.

(b) Primarily the reductions to valuation allowances for North Dakota ITC carryforwards, net of federal benefit, primarily due to a consolidated adjustment to the regulatory liability accrual referenced above; the 2017 change includes $4 million of reduced expense related to the revaluation of federal benefit as a result of TCJA.

Item 16 — Form 10-K Summary

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 22, 2019 By: /s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ BEN FOWKE Ben Fowke	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ ROBERT C. FRENZEL Robert C. Frenzel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
* Lynn Casey	Director
* Richard K. Davis	Director
* Richard T. O’Brien	Director
* David K. Owens	Director
* Christopher J. Policinski	Director
* James Prokopanko	Director
* A. Patricia Sampson	Director
* James J. Sheppard	Director
* David A. Westerlund	Director
* Kim Williams	Director

* Timothy V. Wolf	Director
* Daniel Yohannes	Director
*By: /s/ ROBERT C. FRENZEL Robert C. Frenzel	Attorney-in-Fact

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