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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017
or

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

Commission File Number: 001-3280

Public Service Company of Colorado
(Exact name of registrant as specified in its charter)

Colorado	**84-0296600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1800 Larimer, Suite 1100, Denver, Colorado 80202
(Address of principal executive offices)

Registrant's telephone number, including area code: **(303) 571-7511**

Securities registered pursuant to Section 12(b) of the Act: **None**

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). ☒ Yes ☐ No

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

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

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
(Do not check if smaller reporting company)	Emerging growth company ☐

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

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

As of Feb. 23, 2018, 100 shares of common stock, par value $0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm – Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 3, 2018. Such information set forth under such heading is incorporated herein by this reference hereto.

Public Service Company of Colorado meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with reduced disclosure format permitted by General Instruction I(2).

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This Form 10-K is filed by PSCo. PSCo is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

PART I

Item l — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NCE	New Century Energies, Inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
PSRI	P.S.R. Investments, Inc.
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and subsidiaries

Federal and State Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NERC	North American Electric Reliability Corporation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
GCA	Gas cost adjustment
PCCA	Purchased capacity cost adjustment
PSIA	Pipeline system integrity adjustment
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
TCA	Transmission cost adjustment
WCA	Windsource® cost adjustment

Other Terms and Abbreviations	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CAA	Clean Air Act
CACJA	Clean Air Clean Jobs Act
CO_2	Carbon dioxide

CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CWIP	Construction work in progress
ERCOT	Electric Reliability Council of Texas
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IRC	Internal Revenue Code
ITC	Investment tax credit
JOA	Joint operating agreement
MGP	Manufactured gas plant
MISO	Midcontinent Independent Transmission System Operator, Inc.
Moody's	Moody's Investor Services
MWTG	Mountain West Transmission Group
Native load	Customer demand of retail and wholesale customers whereby a utility has an obligation to serve under statute or long-term contract.
NAV	Net asset value
NOL	Net operating loss
NOx	Nitrogen oxide
O&M	Operating and maintenance
OCI	Other comprehensive income
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PSIA	Pipeline system integrity adjustment
PTC	Production tax credit
PV	Photovoltaic
R&E	Research and experimentation
REC	Renewable energy credit
ROE	Return on equity
RPS	Renewable portfolio standards
SIP	State implementation plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act

Measurements	
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours
GWh	Gigawatt hours

COMPANY OVERVIEW

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.5 million customers and natural gas utility service to approximately 1.4 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado. Although PSCo's large C&I electric retail customers are comprised of many diversified industries, a significant portion of PSCo's large C&I electric sales include: fabricated metal products, communications and health services. For small C&I customers, significant electric retail sales include the following industries: real estate and dining establishments. Generally, PSCo's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The wholesale customers served by PSCo comprised approximately 14 percent of its total KWh sold in 2017.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc. and United Water Company, both of which own certain real estate interests; and Green and Clear Lakes Company, which owns water rights and certain real estate interests. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

PSCo conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 15 to the consolidated financial statements for further discussion relating to comparative segment revenues, net income and related financial information.

ELECTRIC UTILITY OPERATIONS

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. PSCo is authorized by the FERC to make wholesale electric sales at market-based prices to customers outside PSCo's balancing authority area.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — PSCo has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *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 the amount of these costs recovered under its base steam service rates. The SCA rate is revised on a quarterly basis.
- *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 two percent of the customer's bill.
- *WCA* — Premium service for customers who choose to pay for renewable resources.
- *TCA* — Recovers costs associated with 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. PSCo's wholesale customers pay the full cost of certain renewable energy purchase and generation costs through a fuel clause and in exchange receive RECs associated with those resources. The wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2018, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2017	2016	2015	2018 Forecast
PSCo	6,671	6,585	6,284	6,462

The peak demand for PSCo's system typically occurs in the summer. The 2017 system peak demand for PSCo occurred on July 19, 2017. The 2017 system peak demand was higher than 2016 due to warmer July summer weather. The forecast of system peak assumes normal weather conditions.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — PSCo has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a periodic capacity charge and an energy charge for energy actually purchased. PSCo also contracts to purchase power for both wind and solar resources. In addition, PSCo makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to 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 PSCo's customers.

Rush Creek Wind Ownership Proposal — In 2016, the CPUC granted PSCo a CPCN to build, own and operate a 600 MW wind generation facility in Colorado at Rush Creek. The CPCN includes a hard cost-cap of $1.096 billion (including transmission costs) and a capital cost sharing mechanism between customers and PSCo of 82.5 percent to customers and 17.5 percent to PSCo for every $10 million the project comes in below the cost-cap.

All major contracts required to complete the project have been executed. PTC components for safe harboring the facility have been fabricated and construction began in April 2017.

Investment costs will be recovered through the RESA and ECA riders until PSCo's next rate case following Rush Creek's in-service date. The wind generation facility is anticipated to be in service in October 2018.

Colorado Energy Plan (CEP) — In 2016, PSCo filed its 2016 Electric Resource Plan (ERP) which included the estimated need for additional generation resources through spring of 2024. In 2017, PSCo filed an updated capacity need with the CPUC of 450 MW in 2023.

In August 2017, PSCo and various other stakeholders filed a stipulation agreement proposing the CEP, an alternative plan that increases the amount of new resources sought under the ERP. The CEP would increase PSCo's potential capacity need up to 1,110 MW due to the proposed retirement of two coal units. The major components include:

- Early retirement of 660 MWs of coal-fired generation at Comanche Units 1 (2022) and 2 (2025);
- Accelerated depreciation for the early retirement of the two Comanche units and establishment of a regulatory asset to collect the incremental depreciation expense and related costs;
- A RFP for up to 1,000 MW of wind, 700 MW of solar and 700 MW of natural gas and/or storage;
- Utility ownership targets of 50 percent renewable generation resources and 75 percent of natural gas-fired, storage, or renewable with storage generation resources;
- Reduction of the RESA rider, from two percent to one percent effective beginning 2021 or 2022; and
- Construction of a new transmission switching station to further the development of renewable generating resources.

Hearings were held in February 2018 with two parties opposing both the coal retirements and utility ownership. Fifteen parties in the proceeding support the CEP. The CPUC is expected to rule on the stipulation agreement in March 2018. PSCo is currently evaluating bids from a RFP and anticipates filing its recommended portfolios in April 2018. A CPUC decision on the recommended portfolio is anticipated in the summer of 2018.

Boulder, Colorado Municipalization — In 2011, in the City of Boulder, Colorado (Boulder), voters passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Since that time, 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 as premature and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. Subsequently, the Colorado Supreme Court granted Boulder's petition to review the Court of Appeals decision and oral arguments were held on Feb. 14, 2018. A ruling on the petition is anticipated in 2018.

In 2015, the Boulder District Court (District Court) affirmed a prior CPUC decision that Boulder cannot serve customers outside its city limits; these customers were included in Boulder's plan at the time. The District Court also ruled the CPUC has jurisdiction over the transfer of any facilities to Boulder and in determining how the systems are separated. Further, the District Court found that the CPUC must give approval before Boulder files any condemnation proceeding. Boulder does not have authorization to initiate a condemnation proceeding at this time.

Boulder has filed multiple separation applications, the most recent one being in May 2017, which was challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position, stating PSCo is not required to undertake many of Boulder's proposals, such as acting as a financier and contractor for Boulder. Additionally, the CPUC approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain items, including:

- Filing an agreement between Boulder and PSCo providing permanent rights for PSCo to place and access facilities in Boulder needed to continue to serve its customers;
- Filing a complete and accurate revised list of distribution assets desired to be transferred; and
- Filing an agreement to address payments from Boulder to PSCo for costs of Boulder's municipalization efforts.

Boulder has requested that the CPUC grant an extension through March 13, 2018 to complete such filings. Once those filings have been submitted, additional hearings may be held.

In November 2017, Boulder voters passed certain measures regarding Boulder's pursuit of municipalization, including an extension and increase of the Utility Occupational Tax for funding Boulder's exploration of municipalization.

MWTG — PSCo, along with nine other electric service providers from the Rocky Mountain region, have been considering creating and operating a joint transmission tariff to increase wholesale market efficiency and improve regional transmission planning. In September 2017, the MWTG determined that membership in the SPP RTO could provide opportunities to reduce customer costs, and maximize resource and electric grid utilization. In October 2017, the MWTG commenced negotiations with SPP through the SPP public stakeholder process.

SPP's Board of Directors and organizational groups have begun to address the MWTG's proposed terms for integration into the SPP RTO. Should the MWTG decide to move forward, SPP would make filings with the FERC and PSCo would make filings with the CPUC and the FERC, in the later part of 2018. If approved, MWTG operations within the SPP RTO would not be expected to begin until late 2019 at the earliest. PSCo recently engaged a consultant to conduct an analysis of the benefits associated with membership in the SPP RTO. The analysis assumed gas price forecasts that are lower than gas price forecasts used by the other MWTG utilities in their analysis of the benefits associated with membership in the SPP RTO. PSCo is in the process of evaluating that analysis.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

PSCo Generating Plants	Coal Cost	Coal Percent	Natural Gas Cost	Natural Gas Percent	Weighted Average Owned Fuel Cost
2017	$ 1.56	70%	$ 3.82	30%	$ 2.25
2016	1.75	72	3.79	28	2.33
2015	1.75	75	3.89	25	2.29

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — PSCo normally maintains approximately 35 - 50 days of coal inventory. Coal supply inventories at Dec. 31, 2017 and 2016 were approximately 48 and 36 days of usage, respectively. PSCo has contracted for coal supply to provide 75 percent of its 9.1 million tons of estimated coal requirements in 2018, and a declining percentage of requirements in subsequent years. PSCo's general coal purchasing objective is to contract for approximately 75 percent of requirements for the first year, 40 percent of requirements in year two, and 20 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 100 percent its coal requirements in 2018 and 2019. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas supply in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The 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 discussion.

Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery.

- At Dec. 31, 2017, PSCo's commitments related to gas supply contracts, which expire between 2021 through 2023, were approximately $545 million and commitments related to gas transportation and storage contracts, which expire between 2018 through 2040, were approximately $620 million.
- At Dec. 31, 2016, PSCo's commitments related to gas supply contracts were approximately $654 million and commitments related to gas transportation and storage contracts were approximately $573 million.

PSCo has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2017, PSCo was in compliance with mandated RPS, which requires generation from renewable resources of 20.0 percent of electric retail sales.

Renewable energy as a percentage of PSCo' total energy:

	2017	2016
Renewable	27.7%	28.3%
Wind	23.7	23.7
Hydroelectric, biomass and solar	3.9	4.6

PSCo also offers customer-focused renewable energy initiatives. Windsource allows customers to purchase electricity from renewable sources. The number of customers utilizing Windsource increased to approximately 50,000 in 2017 from 46,000 in 2016.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards® program. Over 34,900 PV systems with approximately 310 MW of aggregate capacity have been installed in Colorado as of Dec. 31, 2017 and over 32,500 PV systems with approximately 276 MW of aggregate capacity were installed as of Dec. 31, 2016. Additionally, 33 community solar gardens with 33.5 MW of capacity have been completed in Colorado as of Dec. 31, 2017.

Wind — PSCo acquires the majority of its wind energy from PPAs. Currently, PSCo has 18 of these agreements in place, with facilities ranging in size from two MW to over 300 MW.

- PSCo had approximately 2,560 MW of wind energy on its system at the end of 2017 and 2016. In addition to receiving purchased wind energy under these agreements, PSCo typically receives wind RECs which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under these contracts was approximately $42 in 2017 and 2016. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, previously executed contracts continued to benefit from improvements in wind technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the federal PTCs. In December 2015, the federal PTCs were extended through 2019 with a phase down on sites that began construction in 2017.

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. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of PSCo, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of PSCo's activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 11 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

Xcel Energy, which includes PSCo, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and CFTC jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations.

Public Utility Regulatory Policies Act (PURPA) Enforcement Complaint against CPUC — In December 2016, Sustainable Power Group, LLC (sPower) petitioned the FERC to initiate an enforcement action in federal court against the CPUC under PURPA. The petition asserts that a December 2016 CPUC ruling, which indicated that a qualifying facility must be a successful bidder in a PSCo resource acquisition bidding process, violated PURPA and FERC rules. In January 2017, PSCo filed a motion to intervene and protest, arguing that the FERC should decline the petition. The CPUC filed a similar pleading. sPower has proposed to construct 800 MW of solar generation and 700 MW of wind generation in Colorado and seeks to require PSCo to contract for these resources under PURPA.

If sPower were to prevail, PSCo's ability to select generation resources through competitive bidding would be negatively affected. However, due to a lack of quorum at the FERC, the FERC did not act on that petition within the sixty days contemplated by PURPA. Subsequently sPower filed a complaint for declaratory and injunctive relief in the United States District Court for the District of Colorado (District Court) requesting that the court find the bidding requirement in the CPUC qualifying facility rules to be unlawful. PSCo intervened in that proceeding and the CPUC filed a motion to dismiss. In June 2017, the United States Magistrate Judge issued a recommendation to the District Court that sPower's complaint be dismissed because sPower failed to establish that it faced a substantial risk of harm. In October 2017, the District Court denied the CPUC's motion to dismiss and instead allowed sPower to file an amended complaint. The case effectively started over and PSCo intervened. The CPUC filed a motion to dismiss the amended complaint which is currently pending before the District Court. The timing of a resolution in this case is unclear.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2017	**2016**	**2015**
Electric sales (Millions of KWh)			
Residential	9,107	9,272	9,112
Large commercial and industrial	6,449	6,371	6,596
Small commercial and industrial	12,796	12,890	12,750
Public authorities and other	274	268	242
Total retail	28,626	28,801	28,700
Sales for resale	4,851	4,672	3,581
Total energy sold	33,477	33,473	32,281
Number of customers at end of period			
Residential	1,252,376	1,235,378	1,218,662
Large commercial and industrial	340	337	337
Small commercial and industrial	160,406	159,299	158,086
Public authorities and other	54,110	54,048	53,944
Total retail	1,467,232	1,449,062	1,431,029
Wholesale	43	34	26
Total customers	1,467,275	1,449,096	1,431,055
Electric revenues (Thousands of Dollars)			
Residential	$ 1,033,324	$ 1,063,526	$ 1,060,626
Large commercial and industrial	421,068	414,797	433,061
Small commercial and industrial	1,227,886	1,204,881	1,220,064
Public authorities and other	52,834	54,070	52,783
Total retail	2,735,112	2,737,274	2,766,534
Wholesale	167,971	152,375	180,716
Other electric revenues	100,725	159,703	168,007
Total electric revenues	$ 3,003,808	$ 3,049,352	$ 3,115,257
KWh sales per retail customer	19,510	19,876	20,055
Revenue per retail customer	$ 1,864	$ 1,889	$ 1,933
Residential revenue per KWh	11.35 ¢	11.47 ¢	11.64 ¢
Large commercial and industrial revenue per KWh	6.53	6.51	6.57
Small commercial and industrial revenue per KWh	9.60	9.35	9.57
Total retail revenue per KWh	9.55	9.50	9.64
Wholesale revenue per KWh	3.46	3.26	5.05

Energy Source Statistics

	Year Ended Dec. 31					
	2017		2016		2015	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	14,609	44%	15,895	47%	18,601	54%
Natural Gas	9,195	28	8,632	25	7,948	23
Wind [(a)]	7,804	24	8,106	24	6,699	19
Hydroelectric	624	2	1,179	3	662	2
Other [(b)]	670	2	393	1	705	2
Total	32,902	100%	34,205	100%	34,615	100%
Owned generation	23,053	70%	22,753	67%	22,981	66%
Purchased generation	9,849	30	11,452	33	11,634	34
Total	32,902	100%	34,205	100%	34,615	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. PSCo uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Distributed generation from the Solar*Rewards program is not included, and was approximately 393, 396 and 245 million net KWh for 2017, 2016, and 2015, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

PSCo operates a natural gas local distribution company in Colorado. The most significant developments in the natural gas operations of PSCo are uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small C&I customer, as a result of improved building construction technologies, higher appliance efficiencies, and conservation. From 2000 to 2017, average annual sales to the typical PSCo residential customer declined 17 percent, while sales to the typical small C&I customer declined 12 percent, each on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, high prices can encourage further efficiency efforts by customers.

Pipeline Safety Act **—** The Pipeline Safety, Regulatory Certainty, and Job Creation Act (Pipeline Safety Act) requires additional 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. In April 2016, the PHMSA released proposed rules that address this verification requirement along with a number of other significant changes to gas transmission regulations. These changes include requirements around use of automatic or remote-controlled shut-off valves, testing of certain previously untested transmission lines and expanding integrity management requirements. The Pipeline Safety Act also includes a maximum penalty for violating pipeline safety rules of $2 million per day for related violations.

PHMSA is currently working through the rule with its Pipeline Advisory Committee. Current estimates are the rule will likely go into effect in late 2018 or early 2019.

PSCo has been taking actions that were intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA rider.

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 under the Federal Natural Gas Act. PSCo is subject to the DOT and the CPUC with regards to pipeline safety compliance.

Purchased Natural Gas and Conservation Cost-Recovery Mechanisms — PSCo has retail adjustment clauses that recover purchased natural gas and other resource costs:

- *GCA* — Recovers the actual costs of purchased natural gas and transportation to meet the requirements of its customers 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 associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for PSCo was 1,948,167 MMBtu, which occurred on Jan. 5, 2017 and 1,932,070 MMBtu, which occurred on Dec. 17, 2016.

PSCo purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,818,151 MMBtu per day, which includes 854,852 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo's city gate meter stations.

PSCo is required by CPUC regulations to file a natural gas purchase plan each year projecting and describing the quantities of natural gas supplies, upstream services and the costs of those supplies and services for the 12-month period of the following year. PSCo is also required to file a natural gas purchase report by October of each year reporting actual quantities and costs incurred for natural gas supplies and upstream services for the previous 12-month period.

Natural Gas Supply and Costs

PSCo actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, PSCo conducts natural gas price hedging activities that have been approved by the CPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by PSCo's regulated retail natural gas distribution business:

2017	$	3.45
2016		3.27
2015		3.92

The cost of natural gas in 2017 increased due to higher wholesale commodity prices.

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2017, PSCo was committed to approximately $1.4 billion in such obligations under these contracts, which expire in various years from 2018 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2017, PSCo purchased natural gas from approximately 31 suppliers.

See Items 1A and 7 for further discussion of natural gas supply and costs.

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2017	2016	2015
Natural gas deliveries (Thousands of MMBtu)			
Residential	88,843	90,941	92,001
Commercial and industrial	37,305	38,093	38,405
Total retail	126,148	129,034	130,406
Transportation and other	124,211	117,462	108,860
Total deliveries	250,359	246,496	239,266
Number of customers at end of period			
Residential	1,284,644	1,269,338	1,254,056
Commercial and industrial	100,802	100,718	100,389
Total retail	1,385,446	1,370,056	1,354,445
Transportation and other	7,649	7,261	6,936
Total customers	1,393,095	1,377,317	1,361,381
Natural gas revenues (Thousands of Dollars)			
Residential	$ 652,913	$ 611,804	$ 678,909
Commercial and industrial	247,582	228,103	257,287
Total retail	900,495	839,907	936,196
Transportation and other	94,719	117,814	70,470
Total natural gas revenues	$ 995,214	$ 957,721	$ 1,006,666
MMBtu sales per retail customer	91.05	94.18	96.28
Revenue per retail customer	$ 650	$ 613	$ 691
Residential revenue per MMBtu	7.35	6.73	7.38
Commercial and industrial revenue per MMBtu	6.64	5.99	6.70
Transportation and other revenue per MMBtu	0.76	1.00	0.65

GENERAL

Seasonality

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, PSCo’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 discussion.

Competition

PSCo is a vertically integrated utility, subject to traditional cost-of-service regulation. However, PSCo is subject to different public policies that promote competition and the development of energy markets. PSCo's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with solar generation (typically rooftop solar or solar gardens) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states, including Colorado, have policies designed to promote the development of solar and other distributed energy resources through significant incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to PSCo's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, PSCo and its wholesale customers can purchase generation resources from competing wholesale suppliers and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions, including the CPUC, have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. PSCo also has franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew a franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. While facing these challenges, PSCo believes its rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

PSCo's facilities are regulated by federal and state environmental agencies. These agencies 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. PSCo has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. PSCo's facilities have been designed and constructed to operate in compliance with applicable environmental standards. 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 PSCo's operations. See Notes 11 and 12 to the consolidated financial statements for further discussion.

There are significant present and future environmental regulations to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. PSCo has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If these future environmental regulations do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. PSCo believes, based on prior state commission practice, it would recover the cost of these initiatives through rates.

EMPLOYEES

As of Dec. 31, 2017, PSCo had 2,400 full-time employees and two part-time employees, of which 1,835 were covered under collective-bargaining agreements. See Note 8 to the consolidated financial statements for further discussion.

Item 1A — Risk Factors

Xcel Energy, which includes PSCo, is subject to a variety of risks, many of which are beyond our control. Important risks that may adversely affect the business, financial condition and results of operations are further described below. These risks should be carefully considered together with the other information set forth in this report and in 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 the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economies and the environment when identifying, assessing, managing and mitigating risk. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process 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 our strategy. The business planning process also identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

At a threshold level, PSCo has developed a robust compliance program and promotes a culture of compliance, including tone at the top, which mitigates risk. The process for risk mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups and overall business management to mitigate the risks inherent in the implementation of strategy. Building on this culture of compliance, management further mitigates risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of internal corporate areas such as internal audit, the corporate controller and legal services.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents a periodic assessment of key risks to the Board of Directors. The presentation and the discussion of the key risks provides the Board of Directors with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Management also provides information to the Board of Directors in presentations and communications over the course of the year.

Overall, the Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of PSCo. Processes are in place to ensure appropriate risk oversight, as well as identification and consideration of new risks. The Board of Directors regularly reviews management's key risk assessment informed by these processes, and analyzes areas of existing and future risks and opportunities.

Risks Associated with Our Business

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 past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain permits, licenses, and other approvals and to comply with a wide variety of environmental requirements including those for protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archaeological and historical resources). Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, shift generation to lower-emitting, but potentially more costly facilities, install pollution control equipment at our facilities, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities, either due to the difficulty in assuring compliance or that the costs of compliance makes operation of the units no longer economical. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. 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 certain other parties, caused environmental contamination.

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material effect on our results of operations. 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 or other environmental requirements, it could have a material effect on our results of operations, financial position or cash flows.

In addition, existing environmental laws or regulations may be revised, and new laws or regulations may be adopted or become applicable to us, including but not limited to, regulation of mercury, NOx, SO_2, CO_2 and other GHGs, particulates, cooling water intakes, water discharges and ash management. 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 from climate change can include changes in weather conditions, changes in precipitation and extreme weather events.

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. 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 additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms and associated 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. Changes in precipitation resulting in droughts or water shortages, whether caused by climate change or otherwise, could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought or water depletion conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economic health, which could impact our revenues. Our financial performance is tied to the health of the regional economies we serve. 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 or additional environmental regulation 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.

Financial Risks

Our profitability depends in part on our ability to recover costs from our customers and there may be changes in circumstances or in the regulatory environment that impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The CPUC regulates many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service, the sale of electric energy in interstate commerce and certain natural gas transactions in interstate commerce.

The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment. We provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of our costs incurred in a test year. We are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates we are allowed to charge may or may not match our costs at any given time. While 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 the applicable regulatory commission will judge all of our costs to have been prudent, which could result in cost disallowances, or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements 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 may increase costs of construction and operations. Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers, or these factors could cause us to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are generally 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 hence could materially and adversely affect our ability to meet our financial obligations, including debt payments.

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

We cannot be assured that any of our current ratings will remain in effect for any given period of time, or that a rating will not be lowered or withdrawn entirely by a rating agency. Significant events including a major disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes, among others, 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, we may enter into certain procurement and derivative 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 in nature and are impacted by numerous issues and events throughout the world economy. Capital market disruption events and resulting broad financial market distress could prevent us from issuing short term commercial paper, issuing new securities or cause us to issue securities with less than ideal 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 master pension trust, 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 to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to various 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, MISO and ERCOT, in which any credit losses are socialized to all market participants.

We do have additional indirect credit exposures to various domestic and foreign financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long-term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in technical default under the contract, which would enable us to exercise our contractual rights.

Increasing costs associated with our defined benefit retirement plans and other employee benefits may adversely affect our results of operations, financial position or liquidity.

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, including mortality tables, have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans with modifications that allowed additional flexibility in the timing of contributions. 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 PSCo could trigger settlement accounting and could require PSCo to recognize material incremental pension expense related to unrecognized plan losses in the year these 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 operating results, financial position, and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Changes in industry standards utilized by management 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.

Federal tax law may significantly impact our business.

PSCo collects through regulated rates its estimated federal, state and local tax payments. There are a number of provisions in federal tax law designed to incentivize capital investments which have benefited our customers by keeping our utility subsidiaries' rates lower than rates calculated without such provisions. Examples include the use of accelerated depreciation for most of our capital investments, PTCs for wind energy, ITCs for solar energy and R&E tax credits and deductions. 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 could change the economics of resources and our resource selections. While regulation allows us to incorporate changes in tax law into the rate-setting process, 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.

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 a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. Our electric transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and widespread outages which could cause substantial financial losses. In addition, these natural gas and electric risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. We maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material effect on our financial position and results of operations. For our natural gas transmission or distribution lines located near populated areas, the level of potential damages resulting from these risks is greater.
Additionally, for natural gas the operating or other 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.

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

Most electric utility investments are long-lived and are planned to be used for decades. Transmission and generation investments typically have long lead times, and therefore 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 over the planning horizon 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, public policy has driven increases in appliance and lighting efficiency and energy efficient buildings, wider adoption and lower cost of renewable generation and distributed generation, including community solar gardens and customer-sited solar, 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. Over time, customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if PSCo 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 also 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.

The resource plans reviewed and approved by our state regulators assume continuation of the traditional utility cost of service model under which utility costs are recovered from customers as they receive the benefit of service. PSCo is engaged in significant and ongoing infrastructure investment programs to accommodate renewable distributed generation and maintain high system reliability. Changing customer expectations and changing technologies are requiring significant investments in advanced grid infrastructure. This also increases the exposure to potential outdating of technologies and the resultant risks. PSCo is also investing in renewable and natural gas-fired generation to reduce our CO_2 emissions profile. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Early plant retirements that may result from these changes could expose us to premature financial obligations, which could result in less than full recovery of all remaining costs. Both decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation puts downward pressure on load growth. This could lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states served by a single system 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.

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

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets in which we operate, emission allowances and/or renewable energy credits are also needed to comply with various statutes and commission rulings associated with energy transactions. 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 (mark-to-market accounting). 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.

If we encounter market supply shortages or our suppliers are otherwise unable to meet their contractual obligations, we may be unable to fulfill our contractual obligations to our customers at previously anticipated costs. Therefore, a significant disruption could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments could 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 may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues depends on our operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation including rail shipments of coal, electric generation capacity, transmission, natural gas pipeline capacity, etc. Failure to provide service due to disruptions could also result in fines, penalties or cost disallowances through the regulatory process.

As we are a subsidiary of Xcel Energy Inc., we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If Xcel Energy Inc. were to become obligated to make payments under various guarantees and bond indemnities or to fund its other contingent liabilities, or if either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s credit rating below investment grade, Xcel Energy Inc. may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures. If either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2017, Xcel Energy Inc. and its utility subsidiaries had approximately $14.5 billion of long-term debt and $1.3 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees. As of Dec. 31, 2017, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $19 million and immaterial exposure. Xcel Energy also had additional guarantees of $53 million at Dec. 31, 2017 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. In 2017, 2016 and 2015 we paid $334 million, $337 million and $331 million of dividends to Xcel Energy Inc., respectively. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for PSCo is imposed by its credit facility, which limits the debt-to-total capitalization ratio. See Item 5 for further discussion on dividend limitations.

Public Policy Risks

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

Increased public awareness and concern regarding climate change may result in more state, regional and/or federal requirements to reduce or mitigate the effects of GHGs. Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating 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. International agreements could have an impact to the extent they lead to future federal or state regulations.

In 2015, the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions"), with a goal of holding the increase in global average temperature to below 2^{o} Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5^{o} Celsius. If implemented, the Paris Agreement could result in future additional GHG reductions in the United States. On June 21, 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement. Such a withdrawal, under terms of the Agreement, becomes effective in four years. Many state and local government entities, however, have indicated that they intend to pursue GHG mitigation with a goal of achieving the GHG reductions in the United States anticipated by the Paris Agreement.

We have been, and in the future may be, subject to climate change lawsuits. An adverse outcome in any of these cases 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, cash flows and financial condition if such costs are not recovered through regulated rates.

Some states and localities have indicated a desire to continue to pursue climate policies even in the absence of federal mandates. All of the steps that PSCo 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 PSCo in a good position to meet federal standards under the CPP or the Paris Agreement, repeal of these policies would not impact those state-endorsed actions and plans.

Whether under state or federal programs, an important factor is our ability to recover the costs incurred to comply with any regulatory requirements in a timely manner. 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.

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 now impose penalties of up to $1.2 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. Under statute, the FERC can adjust penalties for inflation. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. Additionally, the PHMSA, the Occupational Safety and Health Administration and other federal agencies also 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 in the event of non-compliance. If a serious reliability or safety incident did occur, it could have a material effect on our operations or financial results.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in our customer base is correlated with economic conditions. While the number of customers is growing, sales growth is relatively modest due to an increased focus on energy efficiency including federal standards for appliance and lighting efficiency and distributed generation, primarily solar PV. Instability in the financial markets also may affect the cost of capital and our ability to raise capital, which is discussed in the capital market risk factor section above.

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 increased bad debt.

Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., 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 costs of the materials we use. We may be at risk for higher than anticipated inflation both with respect to our own workforce, as well as our materials and labor that we contract for with others. There may be delays before these higher costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, threats of terrorism or disruptions in normal operating conditions due to localized or regional events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any such 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 and results of operations. 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. In addition, we may experience additional capital and operating costs to implement security for our plants, such as additional physical plant security and additional security personnel. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection. In addition, we may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, the insurance we are able to obtain 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, as well as our brand and reputation. Because our generation, the transmission systems and local natural gas distribution companies 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 (such as severe storm, severe temperature extremes, wildfires, solar storms, generator or transmission facility outage, breakdown or failure of equipment, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or any disruption of work force such as may be caused by flu or other epidemic) 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 financial condition and results.

The degree to which we are able to maintain day-to-day operations in response to unforeseen events will in part determine the financial impact of certain events on our financial condition and results. It is difficult to predict the magnitude of such events and associated impacts.

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

We operate in an industry that requires the continued operation of sophisticated information technology and 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 and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (such as information about 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 exposing 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 regulatory scrutiny at both the federal and state level. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and corresponding 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 designed 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 were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. 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.

Rising energy prices could negatively impact our business.

Although commodity prices are currently relatively low, 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, 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 as compared with expenditures for fuel purchases could have an impact on our cash flows. Low fuel costs could have a positive impact on sales, though low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

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 throughout our service territory, and 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 with specific qualifications to perform work both for ongoing operations and maintenance and for capital construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance. Cyber security breaches seen in the news 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.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of PSCo is subject to the lien of its first mortgage bond indenture.

Electric Utility Generating Stations:

Station, Location and Unit	Fuel	Installed	Summer 2017 Net Dependable Capability (MW)	
Steam:				
Comanche-Pueblo, Colo.				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(a)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83	(b)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	233	(c)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505	
Valmont-Boulder, Colo., 1 Unit	Coal	1964	—	(d)
Combustion Turbine:				
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264	
Cherokee-Denver, Colo., 1 Unit	Natural Gas	1968	310	(e)
Cherokee-Denver, Colo., 3 Units	Natural Gas	2015	576	
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	968	
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	171	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
		Total	5,086	

(a) Based on PSCo's ownership interest of 67 percent of Unit 3.

(b) Based on PSCo's ownership interest of 10 percent. Craig Unit 1 is expected to be early retired in approximately 2025.

(c) Based on PSCo's ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

(d) Valmont Unit 5 was retired in the third quarter of 2017.

(e) Cherokee Unit 4 was fuel switched from coal to natural gas in the third quarter of 2017.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2017:

Conductor Miles	
345 KV	2,630
230 KV	12,911
138 KV	92
115 KV	4,969
Less than 115 KV	76,998

PSCo had 230 electric utility transmission and distribution substations at Dec. 31, 2017.

Natural gas utility mains at Dec. 31, 2017:

Miles	
Transmission	2,315
Distribution	22,540

Item 3 — Legal Proceedings

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

Additional Information

See Note 12 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1 and Note 11 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

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

PSCo is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities. PSCo's dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

See Note 4 to the financial statements for further discussion of PSCo's dividend policy.

The dividends declared during 2017 and 2016 were as follows:

(Thousands of Dollars)	2017	2016
First quarter	$ 87,104	$ 83,914
Second quarter	83,978	86,509
Third quarter	88,589	82,785
Fourth quarter	76,195	74,208

Item 6 — Selected Financial Data

This is omitted per conditions set forth in general instructions I (1) (a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

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

Discussion of financial condition and liquidity for PSCo is omitted per conditions set forth in general instructions I (1) (a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in general instructions I (2) (a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on PSCo's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and related notes to the consolidated financial statements.

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 TCJA's impact to PSCo and its customers, as well as assumptions and other statements identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017 (including risk factors listed from time to time by PSCo in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of PSCo and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where PSCo has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by PSCo and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates, or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

Results of Operations

PSCo's net income was approximately $494 million for 2017, compared with approximately $463 million for 2016. The increase in earnings, driven by higher electric and natural gas margins, AFUDC primarily related to the Rush Creek wind project and a lower ETR, was partially offset by higher depreciation expense, interest charges and the impact of unfavorable weather.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas and coal 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. The following table details the electric revenues and margin:

(Millions of Dollars)	2017	2016
Electric revenues	$ 3,004	$ 3,049
Electric fuel and purchased power	(1,127)	(1,196)
Electric margin	$ 1,877	$ 1,853

The following tables summarize the components of the changes in electric revenues and electric margin for the year ended Dec. 31:

Electric Revenues

(Millions of Dollars)	2017 vs. 2016
Fuel and purchased power cost recovery	$ (58)
DSM program revenues (offset by expenses)	6
Non-fuel riders	5
Other, net	2
Total decrease in electric revenues	$ (45)

Electric Margin

(Millions of Dollars)	2017 vs. 2016
DSM program revenues (offset by expenses)	$ 6
Non-fuel riders	5
Earnings test	3
Fuel handling and procurement	3
Trading	3
Other, net	4
Total increase in electric margin	$ 24

Natural Gas Revenues and Margin

Total natural gas expense varies with changing sales 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. The following table details natural gas revenues and margin:

(Millions of Dollars)	2017	2016
Natural gas revenues	$ 995	$ 958
Cost of natural gas sold and transported	(459)	(425)
Natural gas margin	$ 536	$ 533

The following tables summarize the components of the changes in natural gas revenues and natural gas margin for the year ended Dec. 31:

Natural Gas Revenues

(Millions of Dollars)	2017 vs. 2016
Purchased natural gas adjustment clause recovery	$ 32
Infrastructure and integrity riders	13
Estimated impact of weather	(4)
Retail rate decrease	(4)
Total increase in natural gas revenues	$ 37

Natural Gas Margin

(Millions of Dollars)	2017 vs. 2016
Infrastructure and integrity riders	$ 13
Estimated impact of weather	(4)
Retail rate decrease	(4)
Other, net	(2)
Total increase in natural gas margin	$ 3

Non-Fuel Operating Expenses and Other Items

DSM Program Expenses — DSM program expenses increased $7 million, or 5.8 percent, for 2017 compared with 2016. The increase was due to higher recovery rates. DSM expenses are generally recovered concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization expense increased $28 million, or 6.3 percent, for 2017 compared with 2016. The increase was primarily attributable to capital investments as well as a new enterprise resource planning system.

AFUDC, Equity and Debt — AFUDC increased by $16 million for 2017 compared with 2016. The increase was primarily due to higher CWIP, particularly the Rush Creek wind project.

Interest Charges — Interest charges increased by $9 million, or 5.0 percent, for 2017 compared with 2016. The increase is primarily due to higher long-term debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes **—** Income tax expense decreased $22 million for 2017 compared with 2016. The decrease in income tax expense was primarily due to the estimated one-time, non-cash, income tax benefit recognized in the fourth quarter related to the TCJA (see Note 7) and increased permanent plant-related adjustments. The ETR was 33.8 percent for 2017 compared with 37.1 percent for 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

Derivatives, Risk Management and Market Risk

PSCo is 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 discussion of market risks associated with derivatives.

PSCo 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, when necessary, 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 PSCo expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose PSCo to some credit and nonperformance risk.

Though no material non-performance risk currently exists with the counterparties to PSCo's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the master pension trust, as well as PSCo's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk **—** PSCo is exposed to commodity price risk in its 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 for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. PSCo'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 **—** PSCo conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. PSCo's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by the policy.

At Dec. 31, 2017, the fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Thousands of Dollars)	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
PSCo	1	$ 291	$ 179	$ —	$ —	$ 470

1 — Prices actively quoted or based on actively quoted prices.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2017	2016
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ (188)	$ 112
Contracts realized or settled during the period	(775)	(654)
Commodity trading contract additions and changes during the period	1,433	354
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 470	$ (188)

At Dec. 31, 2017, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.6 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.6 million. At Dec. 31, 2016, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.9 million, whereas a 10 percent decrease would increase pretax income by approximately $0.9 million.

PSCo's wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (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. The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2017	$ 0.18	$ 3.00	$ 0.21	$ 0.66	$ 0.04
2016	0.09	3.00	0.16	0.38	0.05

Interest Rate Risk — PSCo is subject to the risk of fluctuating interest rates in the normal course of business. PSCo'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.

At Dec. 31, 2017, a 100-basis-point change in the benchmark rate on PSCo's variable rate debt would have no impact on annual pretax interest expense, and at Dec. 31, 2016 a 100-basis-point change in the benchmark rate on PSCo's variable rate debt would impact annual pretax interest expense by approximately $1.3 million. See Note 10 to the consolidated financial statements for a discussion of PSCo's interest rate derivatives.

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

At Dec. 31, 2017, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $17.4 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $5.5 million. At Dec. 31, 2016, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $14.3 million, while a decrease in prices of 10 percent would have resulted in a decrease in credit exposure of $2.2 million.

PSCo conducts standard credit reviews for all counterparties. PSCo employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. 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 PSCo's credit risk.

Fair Value Measurements

PSCo follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 10 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — PSCo continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and 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, 2017. PSCo also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2017.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of forward and option contracts that are long-term in nature or relate to inactive delivery locations. Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts for inactive delivery locations and for contracts that extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were immaterial Level 3 commodity derivative assets or liabilities at Dec. 31, 2017.

Item 8 — Financial Statements and Supplementary Data

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

See Note 17 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of PSCo is responsible for establishing and maintaining adequate internal control over financial reporting. PSCo's internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and PSCo'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.

In 2016, PSCo implemented the general ledger modules of a new enterprise resource planning system. PSCo initiated and implemented additional work management systems modules in 2017. PSCo does not believe this implementation had an adverse effect on its internal control over financial reporting.

PSCo management assessed the effectiveness of PSCo's internal control over financial reporting as of Dec. 31, 2017. 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, 2017, PSCo's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 23, 2018	Feb. 23, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Public Service Company of Colorado

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Company of Colorado and subsidiaries (the “Company”) as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, cash flows, and common stockholder’s equity, for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2018

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

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2017	2016	2015
Operating revenues			
Electric	$ 3,003,808	$ 3,049,352	$ 3,115,257
Natural gas	995,214	957,721	1,006,666
Steam and other	43,487	40,723	41,590
Total operating revenues	4,042,509	4,047,796	4,163,513
Operating expenses			
Electric fuel and purchased power	1,126,660	1,196,417	1,246,666
Cost of natural gas sold and transported	458,717	425,410	501,824
Cost of sales — steam and other	16,146	15,872	17,788
Operating and maintenance expenses	762,817	762,416	761,901
Demand side management program expenses	125,029	118,175	128,681
Depreciation and amortization	471,515	443,555	411,667
Taxes (other than income taxes)	195,695	196,330	195,285
Total operating expenses	3,156,579	3,158,175	3,263,812
Operating income	885,930	889,621	899,701
Other income, net	9,852	3,817	2,964
Allowance for funds used during construction — equity	29,803	18,557	14,485
Interest charges and financing costs			
Interest charges — includes other financing costs of $6,281, $6,289 and $6,285, respectively	190,694	181,631	177,430
Allowance for funds used during construction — debt	(11,407)	(7,045)	(5,522)
Total interest charges and financing costs	179,287	174,586	171,908
Income before income taxes	746,298	737,409	745,242
Income taxes	252,179	273,918	278,440
Net income	$ 494,119	$ 463,491	$ 466,802

See Notes to Consolidated Financial Statements

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2017	2016	2015
Net income	$ 494,119	$ 463,491	$ 466,802
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $(3), $(138), and $0	(5)	(223)	—
Amortization of losses included in net periodic benefit cost, net of tax of $4, $2, and $0, respectively	5	3	—
	—	(220)	—
Derivative instruments:			
Net fair value decrease, net of tax of $0, $0, and $(20), respectively	—	—	(30)
Reclassification of losses to net income, net of tax of $610, $648, and $39, respectively	1,005	1,056	72
	1,005	1,056	42
Other comprehensive income	1,005	836	42
Comprehensive income	$ 495,124	$ 464,327	$ 466,844

See Notes to Consolidated Financial Statements

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2017	2016	2015
Operating activities			
Net income	$ 494,119	$ 463,491	$ 466,802
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	475,592	446,179	416,427
Demand side management program amortization	672	2,138	3,509
Deferred income taxes	207,817	222,002	277,896
Amortization of investment tax credits	(2,803)	(2,805)	(2,807)
Allowance for equity funds used during construction	(29,803)	(18,557)	(14,485)
Provision for bad debts	14,303	14,121	13,052
Net realized and unrealized hedging and derivative transactions	2,364	1,325	2,414
Other	6	(388)	2,500
Changes in operating assets and liabilities:			
Accounts receivable	(2,229)	(14,227)	8,872
Accrued unbilled revenues	1,277	(20,866)	17,837
Inventories	(9,099)	172	33,417
Prepayments and other	188	68,693	10,483
Accounts payable	20,410	38,439	(40,982)
Net regulatory assets and liabilities	(22,548)	4,143	78,055
Other current liabilities	71,776	1,892	19,654
Pension and other employee benefit obligations	(16,515)	(10,627)	(23,449)
Change in other noncurrent assets	(785)	(6,750)	4,086
Change in other noncurrent liabilities	(2,982)	(22,120)	(35,334)
Net cash provided by operating activities	1,201,760	1,166,255	1,237,947
Investing activities			
Utility capital/construction expenditures	(1,475,697)	(1,113,800)	(995,597)
Proceeds from insurance recoveries	—	608	—
Allowance for equity funds used during construction	29,803	18,557	14,485
Investments in utility money pool arrangement	(954,000)	(444,000)	(196,300)
Repayments from utility money pool arrangement	934,000	444,000	212,300
Other	(657)	(1,460)	—
Net cash used in investing activities	(1,466,551)	(1,096,095)	(965,112)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(129,000)	115,000	(368,000)
Borrowings under utility money pool arrangement	40,000	524,500	165,000
Repayments under utility money pool arrangement	(40,000)	(524,500)	(165,000)
Proceeds from issuance of long-term debt	393,791	244,507	246,751
Repayments of long-term debt	—	(129,500)	—
Capital contributions from parent	335,576	38,755	175,210
Dividends paid to parent	(333,879)	(336,581)	(330,846)
Other	(110)	—	—
Net cash provided by (used in) financing activities	266,378	(67,819)	(276,885)
Net change in cash and cash equivalents	1,587	2,341	(4,050)
Cash and cash equivalents at beginning of period	5,926	3,585	7,635
Cash and cash equivalents at end of period	$ 7,513	$ 5,926	$ 3,585
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (174,978)	$ (171,714)	$ (165,546)
Cash (paid) received for income taxes, net	(7,717)	22,827	13,822
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 183,858	$ 68,870	$ 106,912

See Notes to Consolidated Financial Statements

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31 2017	Dec. 31 2016
Assets		
Current assets		
Cash and cash equivalents	$ 7,513	$ 5,926
Accounts receivable, net	294,403	304,900
Accounts receivable from affiliates	14,719	9,421
Investments in utility money pool arrangement	20,000	—
Accrued unbilled revenues	295,801	297,078
Inventories	214,489	202,220
Regulatory assets	77,337	103,783
Derivative instruments	3,197	10,934
Prepayments and other	35,720	34,559
Total current assets	963,179	968,821
Property, plant and equipment, net	14,025,751	12,849,799
Other assets		
Regulatory assets	950,258	958,429
Derivative instruments	1,009	3,398
Other	27,429	25,637
Total other assets	978,696	987,464
Total assets	$ 15,967,626	$ 14,806,084
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 305,577	$ 5,270
Short-term debt	—	129,000
Accounts payable	492,829	376,186
Accounts payable to affiliates	58,749	98,797
Regulatory liabilities	66,126	101,110
Taxes accrued	222,517	171,862
Accrued interest	48,552	48,619
Dividends payable to parent	76,195	74,208
Derivative instruments	7,348	6,788
Other	92,333	73,022
Total current liabilities	1,370,226	1,084,862
Deferred credits and other liabilities		
Deferred income taxes	1,644,476	2,889,129
Deferred investment tax credits	27,858	30,661
Regulatory liabilities	1,933,488	512,933
Asset retirement obligations	347,769	289,563
Derivative instruments	3,468	7,828
Customer advances	162,614	162,742
Pension and employee benefit obligations	287,783	285,774
Other	58,923	62,201
Total deferred credits and other liabilities	4,466,379	4,240,831
Commitments and contingencies		
Capitalization		
Long-term debt	4,302,698	4,210,936
Common stock — 100 shares authorized of $0.01 par value; 100 shares outstanding at Dec. 31, 2017 and 2016, respectively	—	—
Additional paid in capital	4,032,826	3,633,216
Retained earnings	1,822,229	1,659,239
Accumulated other comprehensive loss	(26,732)	(23,000)
Total common stockholder’s equity	5,828,323	5,269,455
Total liabilities and equity	$ 15,967,626	$ 14,806,084

See Notes to Consolidated Financial Statements

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(amounts in thousands, except share and per share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2014	100	$ —	$ 3,522,788	$1,386,929	$ (23,878)	$ 4,885,839
Net income				466,802		466,802
Other comprehensive income					42	42
Common dividends declared to parent				(330,567)		(330,567)
Contribution of capital by parent			98,036			98,036
Balance at Dec. 31, 2015	100	$ —	$ 3,620,824	$1,523,164	$ (23,836)	$ 5,120,152
Net income				463,491		463,491
Other comprehensive income					836	836
Common dividends declared to parent				(327,416)		(327,416)
Contribution of capital by parent			12,392			12,392
Balance at Dec. 31, 2016	100	$ —	$ 3,633,216	$1,659,239	$ (23,000)	$ 5,269,455
Net income				494,119		494,119
Other comprehensive income					1,005	1,005
Common dividends declared to parent				(335,866)		(335,866)
Contribution of capital by parent			399,610			399,610
Adoption of ASU No. 2018-02				4,737	(4,737)	—
Balance at Dec. 31, 2017	100	$ —	$ 4,032,826	$1,822,229	$ (26,732)	$ 5,828,323

See Notes to Consolidated Financial Statements

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31	
	2017	2016
Long-Term Debt		
First Mortgage Bonds, Series due:		
Aug. 1, 2018, 5.8%	$ 300,000	$ 300,000
June 1, 2019, 5.125%	400,000	400,000
Nov. 15, 2020, 3.2%	400,000	400,000
Sept. 15, 2022, 2.25%	300,000	300,000
March 15, 2023, 2.5%	250,000	250,000
May 15, 2025, 2.9%	250,000	250,000
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000
Sept. 15, 2042, 3.6%	500,000	500,000
March 15, 2043, 3.95%	250,000	250,000
March 15, 2044, 4.3%	300,000	300,000
June 15, 2046, 3.55%	250,000	250,000
June 15, 2047, 3.8%	400,000	—
Capital lease obligations, through 2060, 11.2% — 14.3%	150,658	155,927
Unamortized discount	(13,472)	(12,922)
Unamortized debt expense	(28,911)	(26,799)
Total	4,608,275	4,216,206
Less current maturities	305,577	5,270
Total long-term debt	$ 4,302,698	$ 4,210,936
Common Stockholder's Equity		
Common Stock — 100 shares authorized of $0.01 par value; 100 shares outstanding at Dec. 31, 2017 and 2016, respectively.	$ —	$ —
Additional paid-in capital	4,032,826	3,633,216
Retained earnings	1,822,229	1,659,239
Accumulated other comprehensive loss	(26,732)	(23,000)
Total common stockholder's equity	$ 5,828,323	$ 5,269,455

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Business and System of Accounts — PSCo is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. PSCo's consolidated financial statements and disclosures are presented in accordance with GAAP. All of PSCo's underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — PSCo's consolidated financial statements include its wholly-owned subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. PSCo has investments in several plants and transmission facilities jointly owned with nonaffiliated utilities. PSCo's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and PSCo's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 6 for further discussion of jointly owned generation, transmission and gas facilities, and related ownership percentages.

PSCo evaluates its arrangements and contracts with other entities, including investments, PPAs and fuel contracts, to determine if the other party is a variable interest entity, if PSCo has a variable interest and if PSCo is the primary beneficiary. PSCo follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether PSCo is a variable interest entity's primary beneficiary. See Note 12 for further discussion of variable interest entities.

Use of Estimates — In recording transactions and balances resulting from business operations, PSCo uses estimates based on the best information available. Estimates are used for such items 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. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Regulatory Accounting — PSCo accounts for certain 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 OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or OCI, 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 restructuring or other changes in the regulatory environment occur, PSCo may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on PSCo's financial condition, results of operations and cash flows. See Note 13 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, 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. PSCo presents its revenues net of any excise or other fiduciary-type taxes or fees.

PSCo has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms 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, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

Conservation Programs — PSCo has implemented programs to assist its retail customers in conserving energy and reducing peak demand on the electric and natural gas systems. These programs include approximately 20 unique DSM products, pilots and services for C&I customers, as well as approximately 23 DSM products, pilots and services for residential and low-income customers. Overall, the DSM portfolio provides rebates and/or incentives for nearly 1,000 unique measures.

The costs incurred for DSM programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of DSM program costs and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

PSCo's DSM program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage PSCo's achievement of energy conservation goals. PSCo recognizes regulatory assets to reflect the amount of costs or earned incentives that have not yet been collected from customers.

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 major 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 also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually, and revised, if appropriate.

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.

PSCo records depreciation expense related to its plant 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 2.7, 2.6 and 2.7 percent for the years ended Dec. 31, 2017, 2016 and 2015, respectively.

Leases — PSCo evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 12 for further discussion of leases.

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 PSCo's rate base for establishing utility service rates.

Generally, AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain generation and transmission projects, the CPUC has approved a more current recovery of the cost of capital associated with large capital projects, resulting in a lower recognition of AFUDC. In other cases, the CPUC has allowed an AFUDC calculation greater than the FERC-defined AFUDC rate, resulting in higher recognition of AFUDC.

AROs — PSCo accounts 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. PSCo also recovers 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 discussion of AROs.

Income Taxes — PSCo accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. PSCo defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. PSCo 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 PSCo's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its 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. 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 certain regulatory assets and liabilities related to income taxes, which are summarized in Note 13.

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. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

PSCo 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. PSCo 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.

PSCo reports interest and penalties related to income taxes within the other income and interest charges sections in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries, including PSCo, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries which are recorded directly in equity by the subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 7 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — PSCo 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. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The 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. The 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. PSCo is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customer, see Note 10.

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — PSCo enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

PSCo evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 10 for further discussion of PSCo's risk management and derivative activities.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in electric operating revenues in the consolidated statements of income.

Pursuant to the JOA approved by the FERC, some of the commodity trading margins from PSCo are apportioned to NSP-Minnesota and SPS. Commodity trading activities are not associated with energy produced from PSCo'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 discussion.

Fair Value Measurements — PSCo presents cash equivalents, interest rate derivatives and commodity derivatives 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 as a primary input 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 for an identical contract in an active market, PSCo may use quoted prices for similar contracts, or internally prepared valuation models to determine fair value. For the pension and postretirement plan assets published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. See Note 8 and 10 for further discussion.

Cash and Cash Equivalents — PSCo considers investments in certain instruments, including commercial paper and money market funds, 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. PSCo establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

Inventory — All inventory is recorded at average cost.

RECs — RECs are marketable environmental instruments that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPS enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. PSCo acquires RECs from the generation or purchase of renewable power.

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. As a result of state regulatory orders, PSCo records that cost as a regulatory asset when the amount is recoverable in future rates.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Emission Allowances — Emission allowances, including the annual SO_2 and NOx emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. PSCo follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenues and the operating activities section of the consolidated statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable PSCo 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, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded 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 PSCo’s expected share of the cost.

Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further discussion of environmental costs.

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

Based on regulatory recovery mechanisms, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 8 for further discussion of benefit plans and other postretirement benefits.

Guarantees — PSCo recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as PSCo is released from risk under the guarantee.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2017 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Issued

***Revenue Recognition* —** In May 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. As the appropriate timing of recognition of revenue from contracts with customers in our regulated operations continues to generally be based on the delivery of electricity and natural gas, PSCo's adoption will primarily result in increased disclosures regarding sources of revenues, including alternative revenue programs. The guidance is effective for interim and annual periods beginning after Dec. 15, 2017. PSCo is implementing the standard on a modified retrospective basis, which requires application to contracts with customers effective Jan. 1, 2018.

***Classification and Measurement of Financial Instruments* —** In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01),* which eliminates the available-for-sale classification for marketable equity securities and also replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are to be recognized in earnings. This guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017. The overall impacts of the Jan. 1, 2018 adoption will not be material.

***Leases* —** In February 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which, for lessees, requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. PSCo has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and proposed in *Targeted Improvements, Topic 842* (Proposed ASU 2018-200). As such, agreements entered prior to Jan. 1, 2019 that are currently considered leases are expected to be recognized on the consolidated balance sheet, including contracts for use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for natural gas-fueled generating facilities. PSCo expects that similar agreements entered after Dec. 31, 2018 will generally qualify as leases under the new standard.

***Presentation of Net Periodic Benefit Cost* —** In March 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 element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment and the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. This guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017.

Recently Adopted

Accounting for the TCJA **—** In December 2017, the SEC staff issued Staff Accounting Bulletin No. 118 *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* (SAB 118), to supplement the accounting requirements of ASC Topic 740 *Income Taxes* (ASC Topic 740) as it relates to assessing and recognizing the impacts of the TCJA in the period of enactment. SAB 118 allows an entity to recognize provisional amounts in its financial statements in circumstances in which the entity's assessment is incomplete, but for which a reasonable estimate can be made. Provisional amounts recognized are subject to adjustment for up to one year from the enactment date. For further details, see Note 7 to the consolidated financial statements.

Reporting Comprehensive Income **—** In February 2018, the FASB issued *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, Topic 220 (ASU No. 2018-02),* which addresses the stranded amounts of accumulated OCI which may result from enactment of a new tax law. Though accumulated OCI is presented on a net-of-tax basis, ASC Topic 740 requires that the effects of new tax laws on items in accumulated OCI be recognized without a corresponding adjustment to accumulated OCI, and instead recorded to income tax expense. ASU No. 2018-02 permits stranded amounts of accumulated OCI specifically resulting from the TCJA to be removed from accumulated OCI and reclassified to retained earnings, if elected. PSCo adopted the guidance in the fourth quarter of 2017, and elected to recognize a $4.7 million increase to accumulated other comprehensive loss and retained earnings in the consolidated financial statements for the year ended Dec. 31, 2017, related to a revaluation of deferred income tax assets and liabilities for items in accumulated other comprehensive loss, at the TCJA federal tax rate.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Accounts receivable, net		
Accounts receivable	$ 314,009	$ 324,512
Less allowance for bad debts	(19,606)	(19,612)
	$ 294,403	$ 304,900

(Thousands of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Inventories		
Materials and supplies	$ 68,940	$ 66,161
Fuel	73,893	66,429
Natural gas	71,656	69,630
	$ 214,489	$ 202,220

(Thousands of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Property, plant and equipment, net		
Electric plant	$ 12,627,592	$ 12,304,436
Natural gas plant	4,102,075	3,710,772
Common and other property	1,022,333	919,955
Plant to be retired [(a)]	10,949	31,839
Construction work in progress	1,014,338	484,340
Total property, plant and equipment	18,777,287	17,451,342
Less accumulated depreciation	(4,751,536)	(4,601,543)
	$ 14,025,751	$ 12,849,799

(a) In the third quarter of 2017, PSCo early retired Valmont Unit 5 and converted Cherokee Unit 4 from a coal-fueled generating facility to natural gas. PSCo also expects Craig Unit 1 to be early retired in approximately 2025. Amounts are presented net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that 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. PSCo had no money pool borrowings outstanding during the three months ended Dec. 31, 2017. Money pool borrowings for PSCo were as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2017	Twelve Months Ended Dec. 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	$ 250	$ 250	$ 250
Amount outstanding at period end	—	—	—
Average amount outstanding	—	21	1
Maximum amount outstanding	20	141	34
Weighted average interest rate, computed on a daily basis	0.92%	0.73%	0.41%
Weighted average interest rate at period end	N/A	N/A	N/A

Commercial Paper — PSCo meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. PSCo had no commercial paper borrowings outstanding during the three months ended Dec. 31, 2017. Commercial paper borrowings for PSCo were as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2017	Twelve Months Ended Dec. 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	$ 700	$ 700	$ 700
Amount outstanding at period end	—	129	14
Average amount outstanding	54	24	95
Maximum amount outstanding	268	154	449
Weighted average interest rate, computed on a daily basis	1.08%	0.70%	0.51%
Weighted average interest rate at period end	N/A	0.95	0.60

Letters of Credit — PSCo uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At both Dec. 31, 2017 and 2016, there were $3 million of letters of credit outstanding under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, PSCo must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an aggregate amount exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

PSCo has the right to request an extension of the June 2021 termination date for two additional one-year periods. The extension requests are subject to majority bank group approval.

Other features of PSCo's credit facility include:

- PSCo may increase its credit facility by up to $100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. PSCo was in compliance as its debt-to-total capitalization ratio was 44 percent and 45 percent at Dec. 31, 2017 and 2016, respectively. If PSCo does 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.
- The credit facility has a cross-default provision that provides PSCo will be in default on its borrowings under the facility if PSCo or any of its subsidiaries whose total assets exceed 15 percent of PSCo's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding $75 million.
- PSCo was in compliance with all financial covenants on its debt agreements as of Dec. 31, 2017 and 2016.

At Dec. 31, 2017, PSCo had the following committed credit facility available (in millions):

Credit Facility [a]	Drawn [b]	Available
$ 700	$ 3	$ 697

(a) This credit facility matures in June 2021.
(b) Includes letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. PSCo had no direct advances on the credit facility outstanding at Dec. 31, 2017 and 2016.

Long-Term Borrowings

Generally, all real and personal property of PSCo is subject to the liens of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

In 2017, PSCo issued $400 million of 3.80 percent first mortgage bonds due June 15, 2047. In 2016, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046.

During the next five years, PSCo has long-term debt maturities of $300 million, $400 million, $400 million and $300 million due in 2018, 2019, 2020 and 2022, respectively.

Deferred Financing Costs — Deferred financing costs of approximately $29 million and $27 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2017 and 2016, respectively. PSCo is amortizing these financing costs over the remaining maturity periods of the related debt.

Dividend Restrictions — PSCo's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

5. Preferred Stock

PSCo has authorized the issuance of preferred stock.

Preferred Shares Authorized	Par Value	Preferred Shares Outstanding
10,000,000	$ 0.01	None

6. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by PSCo in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2017:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
Electric Generation:				
Hayden Unit 1	$ 150,441	$ 72,042	$ 830	76%
Hayden Unit 2	148,694	65,493	18	37
Hayden Common Facilities	39,321	19,886	97	53
Craig Units 1 and 2	80,650	38,666	—	10
Craig Common Facilities 1, 2 and 3	38,902	20,116	—	7
Comanche Unit 3	889,630	117,759	476	67
Comanche Common Facilities	24,421	2,092	2,809	82
Electric Transmission:				
Transmission and other facilities, including substations	176,873	67,637	638	Various
Gas Transportation:				
Rifle, Colo. to Avon, Colo.	21,532	7,579	—	60
Gas Transportation Compressor	8,417	616	—	50
Total	$ 1,578,881	$ 411,886	$ 4,868	

PSCo has approximately 816 MW of jointly owned generating capacity. PSCo's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

7. Income Taxes

Federal Tax Reform — In December 2017, the TCJA was signed into law. While the legislation will require interpretations and regulations to be issued by the IRS, the key provisions impacting Xcel Energy (which includes PSCo), generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35 percent to 21 percent;
- 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 percent of taxable income);
- Repeal of the section 199 manufacturing deduction; and
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Entities are required under ASC Topic 740 to recognize the accounting impacts of a tax law change, including the impacts of a change in tax rates on deferred tax assets and liabilities, in the period including the date of the tax law enactment. The SEC staff issued guidance in SAB 118 that supplements the accounting requirements of ASC Topic 740 if elements of the TCJA assessment are not complete, and provides for up to a one year period to finalize the required accounting. Xcel Energy has estimated the effects of the TCJA, which have been reflected in the Dec. 31, 2017 consolidated financial statements. Issuance of U.S. Treasury regulations interpreting the TCJA, other U.S. Treasury and IRS guidance or interpretations of the application of ASC Topic 740 may result in changes to these estimates.

Overall for Xcel Energy, reductions in deferred tax assets and liabilities due to the reduction in corporate federal tax rates result in a net tax benefit. However, as a result of IRS requirements and past regulatory treatment of deferred taxes in the determination of regulated rates of the utility subsidiaries, including deferred taxes related to regulated plant and certain other deferred tax assets and liabilities, the impact was primarily recognized as a regulatory liability refundable to utility customers.

The fourth quarter 2017 estimated accounting impacts of the December 2017 enactment of the new tax law at PSCo included:

- $1.1 billion ($1.5 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21 percent federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $54 million and $50 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;
- $18 million of total estimated income tax benefit related to the federal tax reform implementation, and a $4 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

Xcel Energy has accounted for the state tax impacts of federal tax reform based on currently 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.

Consolidated Appropriations Act, 2016 — In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provided for the following:

- Immediate expensing, or "bonus depreciation," of 50 percent for property placed in service in 2015, 2016, and 2017;
- PTCs at 100 percent of the applicable rate for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;
- ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- R&E credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment.

Federal Audit — PSCO is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. The statutes of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2011	June 2018
2012 - 2013	October 2018
2014	September 2018
2015	September 2019
2016	September 2020

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims that would have resulted in $14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals ("Appeals"). In the third quarter of 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. PSCo did not accrue any income tax benefit related to this adjustment. As of Dec. 31, 2017, the case has been forwarded to the Joint Committee on Taxation.

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. After evaluating the proposed adjustment, Xcel Energy filed a protest with the IRS. Xcel Energy anticipates the issue will be forwarded to Appeals. As of Dec. 31, 2017, 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 uncertain.

State Audits — PSCo is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2017, PSCo's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

***Unrecognized Tax Benefits* —** The 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 of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Unrecognized tax benefit — Permanent tax positions	$ 4.0	$ 2.9
Unrecognized tax benefit — Temporary tax positions	6.1	16.8
Total unrecognized tax benefit	$ 10.1	$ 19.7

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2017	2016	2015
Balance at Jan. 1	$ 19.7	$ 17.4	$ 11.9
Additions based on tax positions related to the current year	1.9	2.7	4.5
Reductions based on tax positions related to the current year	(1.5)	—	(1.5)
Additions for tax positions of prior years	4.4	0.5	2.5
Reductions for tax positions of prior years	(14.4)	(0.9)	—
Balance at Dec. 31	$ 10.1	$ 19.7	$ 17.4

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
NOL and tax credit carryforwards	$ (4.0)	$ (5.8)

It is reasonably possible that PSCo's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and the IRS and state audits resume. As the IRS Appeals progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $2 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits are as follows:

(Millions of Dollars)	2017	2016	2015
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (1.1)	$ (0.4)	$ (0.2)
Interest income (expense) related to unrecognized tax benefits	0.8	(0.7)	(0.2)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (0.3)	$ (1.1)	$ (0.4)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2017, 2016 or 2015.

Other Income Tax Matters — NOL amounts represent the amount of 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)	2017	2016
Federal NOL carryforward	$ 68	$ 260
Federal tax credit carryforwards	30	25
State NOL carryforwards	679	684
State tax credit carryforwards, net of federal detriment [(a)]	17	13
Valuation allowances for state credit carryforwards, net of federal detriment [(b)]	(7)	(3)

(a) State tax credit carryforwards are net of federal detriment of $4 million and $7 million as of Dec. 31, 2017 and 2016, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $2 million and $2 million as of Dec. 31, 2017 and 2016, respectively.

The federal carryforward periods expire between 2021 and 2037. The state carryforward periods expire between 2018 and 2033.

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. The following reconciles such differences for the years ending Dec. 31:

	2017	2016 [(b)]	2015 [(b)]
Federal statutory rate	35.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	3.0%	3.0%	3.0%
Increases (decreases) in tax from:			
Tax reform	(2.4)	—	—
Tax credits recognized, net of federal income tax expense	(0.9)	(0.7)	(0.7)
Regulatory differences - effects of rate changes [(a)]	(0.1)	(0.1)	(0.1)
Regulatory differences - other utility plant items	(0.9)	(0.5)	(0.3)
Change in unrecognized tax benefits	0.2	—	0.1
Other, net	(0.1)	0.4	0.4
Effective income tax rate	33.8%	37.1%	37.4%

(a) The amortization of excess deferred taxes.

(b) The prior periods included in this footnote have been reclassified to conform to current year presentation.

The components of income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2017	2016	2015
Current federal tax expense (benefit)	$ 40,386	$ 45,287	$ (1,166)
Current state tax expense (benefit)	14,577	8,754	(727)
Current change in unrecognized tax (benefit) expense	(7,798)	680	5,244
Deferred federal tax expense	176,410	195,064	246,096
Deferred state tax expense	22,513	27,216	36,450
Deferred change in unrecognized tax expense (benefit)	8,894	(278)	(4,650)
Deferred investment tax credits	(2,803)	(2,805)	(2,807)
Total income tax expense	$ 252,179	$ 273,918	$ 278,440

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2017	2016	2015
Deferred tax (benefit) expense excluding items below	$ (1,244,653)	$ 230,931	$ 285,144
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	1,453,080	(8,418)	(7,229)
Tax expense allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(610)	(511)	(19)
Deferred tax expense	$ 207,817	$ 222,002	$ 277,896

The components of the net deferred tax liability at Dec. 31 were as follows:

(Thousands of Dollars)	2017	2016 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 1,797,023	$ 2,967,162
Regulatory assets	252,353	102,967
Pension expense	60,032	10,016
Other	3,994	3,920
Total deferred tax liabilities	$ 2,113,402	$ 3,084,065
Deferred tax assets:		
Regulatory liabilities	$ 337,973	$ (35,813)
NOL carryforward	39,347	115,328
Tax credit carryforward	39,323	34,658
Deferred investment tax credits	6,872	11,653
Other employee benefits	6,779	15,274
Deferred fuel costs	6,523	10,070
Rate refund	890	7,221
Other	31,219	36,545
Total deferred tax assets	$ 468,926	$ 194,936
Net deferred tax liability	$ 1,644,476	$ 2,889,129

[(a)] The prior period included in this footnote has been reclassified to conform to current year presentation.

8. Benefit Plans and Other Postretirement Benefits

Consistent with the process for rate recovery of pension and postretirement benefits for its employees, PSCo accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy Inc. as multiple employer plans. PSCo is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, PSCo accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for PSCo employees.

Xcel Energy, which includes PSCo, offers various benefit plans to its employees. Approximately 76 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2017, PSCo had 1,835 bargaining employees covered under a collective-bargaining agreement, which expired in May 2017. While collective bargaining is ongoing, the terms and conditions of the agreement are automatically extended.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

> Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.
>
> Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets 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 included in Level 3 are those with inputs requiring significant management judgment or estimation.

Specific valuation methods include the following:

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

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

Investments in commingled funds, 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, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with a few days' notice to annually with 90 days' notice. Private equity 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. Depending on the fund, unscheduled distributions from real estate investments may require approval of the fund or may be redeemed with proper notice, which is typically quarterly with 45-90 days' notice; however, withdrawals from real estate investments 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. *Derivative Instruments* — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

Xcel Energy, which includes PSCo, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, social security benefits. Xcel Energy Inc.'s and PSCo's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (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 unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions attributable to PSCo funded by PSCo's consolidated operating cash flows. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2017 and 2016 were $37 million and $44 million, respectively, of which $3 million and $4 million were attributable to PSCo. In 2017 and 2016, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $5 million and $8 million, respectively, of which $1 million in each year was attributable to PSCo.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to PSCo will be supplemented by PSCo's consolidated operating cash flows as determined necessary. The amount of rabbi trust funding attributable to PSCo is immaterial. Also in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

Xcel Energy Inc. and PSCo base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the historical returns achieved by the asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Xcel Energy Inc. and PSCo continually review pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long term.

- Investment returns in 2017 were above the assumed level of 6.84 percent;
- Investment returns in 2016 were below the assumed level of 6.84 percent;
- Investment returns in 2015 were below the assumed level of 6.81 percent; and
- In 2018, PSCo's expected investment-return assumption is 6.84 percent.

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

The following table presents the target pension asset allocations for PSCo at Dec. 31 for the upcoming year:

	2017	2016
Domestic and international equity securities	34%	36%
Long-duration fixed income and interest rate swap securities	32	31
Short-to-intermediate fixed income securities	18	15
Alternative investments	14	16
Cash	2	2
Total	100%	100%

The 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. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, PSCo's pension plan assets that are measured at fair value as of Dec. 31, 2017 and 2016:

	Dec. 31, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 67,179	$ —	$ —	$ —	$ 67,179
Commingled funds:					
U.S. equity funds	169,624	—	—	—	169,624
Non U.S. equity funds	30,277	—	—	65,822	96,099
U.S. corporate bond funds	137,086	—	—	—	137,086
Emerging market equity funds	—	—	—	103,876	103,876
Emerging market debt funds	24,825	—	—	54,954	79,779
Private equity investments	—	—	—	27,816	27,816
Real estate	—	—	—	64,500	64,500
Other commingled funds	1,601	—	—	38,545	40,146
Debt securities:					
Government securities	—	144,333	—	—	144,333
U.S. corporate bonds	—	102,659	—	—	102,659
Non U.S. corporate bonds	—	16,792	—	—	16,792
Equity securities:					
U.S. equities	37,752	—	—	—	37,752
Other	(9,885)	1,414	—	180	(8,291)
Total	$ 458,459	$ 265,198	$ —	$ 355,693	$ 1,079,350

(Thousands of Dollars)	Dec. 31, 2016 Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 34,957	$ —	$ —	$ —	$ 34,957
Commingled funds:					
U.S. equity funds	165,621	—	—	—	165,621
Non U.S. equity funds	64,710	—	—	57,487	122,197
U.S. corporate bond funds	96,995	—	—	—	96,995
Emerging market equity funds	—	—	—	64,784	64,784
Emerging market debt funds	25,866	—	—	27,837	53,703
Commodity funds	—	—	—	7,497	7,497
Private equity investments	—	—	—	31,828	31,828
Real estate	—	—	—	61,048	61,048
Other commingled funds	—	—	—	74,696	74,696
Debt securities:					
Government securities	—	168,014	—	—	168,014
U.S. corporate bonds	—	86,081	—	—	86,081
Non U.S. corporate bonds	—	13,828	—	—	13,828
Mortgage-backed securities	—	2,179	—	—	2,179
Asset-backed securities	—	1,032	—	—	1,032
Equity securities:					
U.S. equities	27,348	—	—	—	27,348
Other	—	(7,595)	—	—	(7,595)
Total	$ 415,497	$ 263,539	$ —	$ 325,177	$ 1,004,213

There were no assets transferred in or out of Level 3 for the years ended Dec. 31, 2017, 2016 or 2015.

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for PSCo is presented in the following table:

(Thousands of Dollars)	2017	2016
Accumulated Benefit Obligation at Dec. 31	$ 1,285,010	$ 1,213,890
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 1,251,822	$ 1,224,650
Service cost	27,280	25,926
Interest cost	50,558	55,405
Transfer to other plan	—	(9,149)
Plan amendments	(1,096)	206
Actuarial loss	83,531	51,779
Benefit payments	(77,915)	(96,995)
Obligation at Dec. 31	$ 1,334,180	$ 1,251,822

(Thousands of Dollars)	2017	2016
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 1,004,213	$ 1,036,681
Actual return on plan assets	135,552	56,762
Employer contributions	17,500	16,829
Transfer to other plan	—	(9,064)
Benefit payments	(77,915)	(96,995)
Fair value of plan assets at Dec. 31	$ 1,079,350	$ 1,004,213

(Thousands of Dollars)	2017	2016
Funded Status of Plans at Dec. 31:		
Funded status [(a)]	$ (254,830)	$ (247,609)

(a) Amounts are recognized in noncurrent liabilities on PSCo's consolidated balance sheets.

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 543,707	$ 554,999
Prior service credit	(10,593)	(12,155)
Total	$ 533,114	$ 542,844

(Thousands of Dollars)	2017	2016
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	$ 27,662	$ 26,853
Noncurrent regulatory assets	505,171	515,708
Deferred income taxes	69	108
Net-of-tax accumulated OCI	212	175
Total	$ 533,114	$ 542,844
Measurement date	Dec. 31, 2017	Dec. 31, 2016

	2017	2016
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	3.63%	4.13%
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP-2014	RP-2014

Mortality **—** In 2014, the Society of Actuaries published a new mortality table (RP-2014) that increased the overall life expectancy of males and females. In 2014, PSCo adopted this mortality table, with modifications, based on its population and specific experience. During 2017, a new projection table was released (MP-2017). PSCo evaluated the updated projection table and concluded that the methodology currently in use and adopted in 2016 is consistent with the recently updated 2017 table and continues to be representative of PSCo's population.

Cash Flows **—** Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2015 through 2018 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2018, of which $22 million was attributable to PSCo;
- $162 million in 2017, of which $18 million was attributable to PSCo;
- $125 million in 2016, of which $17 million was attributable to PSCo; and
- $90 million in 2015, of which $20 million was attributable to PSCo.

For future years, Xcel Energy and PSCo anticipate contributions will be made as necessary.

Plan Amendments **—** Xcel Energy, which includes PSCo, amended the Xcel Energy Inc. Nonbargaining Pension Plan (South) 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 annual credits contributed to the PSCo Bargaining Plan retirement spending account increased.

Benefit Costs — The components of PSCo's net periodic pension cost were:

(Thousands of Dollars)	2017	2016	2015
Service cost	$ 27,280	$ 25,926	$ 28,260
Interest cost	50,558	55,405	50,857
Expected return on plan assets	(68,535)	(70,769)	(72,590)
Amortization of prior service credit	(3,211)	(3,211)	(3,136)
Amortization of net loss	28,355	26,771	36,377
Net periodic pension cost	34,447	34,122	39,768
(Costs) credits not recognized due to effects of regulation	(2,631)	3,364	(1,464)
Net benefit cost recognized for financial reporting	$ 31,816	$ 37,486	$ 38,304

	2017	2016	2015
Significant Assumptions Used to Measure Costs:			
Discount rate	4.13%	4.66%	4.11%
Expected average long-term increase in compensation level	3.75	4.00	3.75
Expected average long-term rate of return on assets	6.84	6.84	6.81

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy Inc., costs are allocated to PSCo based on Xcel Energy Services Inc. employees' labor costs. Amounts allocated to PSCo were $18 million, $9 million and $10 million in 2017, 2016 and 2015, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2018 pension cost calculations is 6.84 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including PSCo, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets 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 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Defined Contribution Plans

Xcel Energy, which includes PSCo, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for PSCo was approximately $10 million in 2017, 2016 and 2015.

Postretirement Health Care Benefits

Xcel Energy, which includes PSCo, has a contributory health and welfare benefit plan that provides health care and death benefits to certain retirees. Xcel Energy discontinued contributing toward health care benefits for PSCo nonbargaining employees retiring after June 30, 2003. Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. 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.

The following table presents the target postretirement asset allocations for Xcel Energy Inc. and PSCo at Dec. 31 for the upcoming year:

	2017	2016
Domestic and international equity securities	24%	25%
Short-to-intermediate fixed income securities	60	57
Alternative investments	9	13
Cash	7	5
Total	100%	100%

Xcel Energy Inc. and PSCo base the investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and PSCo'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 projected 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 particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

The following tables present, for each of the fair value hierarchy levels, PSCo's proportionate allocation of the total postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2017 and 2016:

	Dec. 31, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 25,724	$ —	$ —	$ —	$ 25,724
Insurance contracts	—	43,524	—	—	43,524
Commingled funds:					
U.S. equity funds	64,899	—	—	—	64,899
U.S fixed income funds	29,946	—	—	—	29,946
Emerging market debt funds	35,402	—	—	—	35,402
Debt securities:					
Government securities	—	50,576	—	—	50,576
U.S. corporate bonds	—	55,323	—	—	55,323
Non U.S. corporate bonds	—	18,712	—	—	18,712
Asset-backed securities	—	20,468	—	—	20,468
Mortgage-backed securities	—	30,231	—	—	30,231
Equity securities:					
Non U.S. equities	30,671	—	—	—	30,671
Other	—	948	—	—	948
Total	$ 186,642	$ 219,782	$ —	$ —	$ 406,424

(Thousands of Dollars)	Dec. 31, 2016 Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 18,288	$ —	$ —	$ —	$ 18,288
Insurance contracts	—	42,046	—	—	42,046
Commingled funds:					
U.S. equity funds	48,462	—	—	—	48,462
U.S fixed income funds	24,132	—	—	—	24,132
Emerging market debt funds	27,089	—	—	—	27,089
Other commingled funds	—	—	—	48,922	48,922
Debt securities:					
Government securities	—	33,600	—	—	33,600
U.S. corporate bonds	—	55,473	—	—	55,473
Non U.S. corporate bonds	—	15,384	—	—	15,384
Asset-backed securities	—	16,845	—	—	16,845
Mortgage-backed securities	—	25,563	—	—	25,563
Equity securities:					
Non U.S. equities	36,462	—	—	—	36,462
Other	—	1,289	—	—	1,289
Total	$ 154,433	$ 190,200	$ —	$ 48,922	$ 393,555

There were no assets transferred in or out of Level 3 for the years ended Dec. 31, 2017, 2016 or 2015.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for PSCo is presented in the following table:

(Thousands of Dollars)	2017	2016
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 421,823	$ 403,574
Service cost	767	768
Interest cost	16,765	18,070
Medicare subsidy reimbursements	993	1,901
Plan participants' contributions	5,971	5,376
Actuarial loss	18,314	27,355
Benefit payments	(35,386)	(35,221)
Obligation at Dec. 31	$ 429,247	$ 421,823

(Thousands of Dollars)	2017	2016
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 393,555	$ 399,442
Actual return on plan assets	36,975	18,590
Plan participants' contributions	5,971	5,376
Employer contributions	5,309	5,368
Benefit payments	(35,386)	(35,221)
Fair value of plan assets at Dec. 31	$ 406,424	$ 393,555

(Thousands of Dollars)	2017	2016
Funded Status at Dec. 31:		
Funded status [a]	$ (22,823)	$ (28,268)

[a] Amounts are recognized in noncurrent liabilities on PSCo's consolidated balance sheets as of Dec. 31, 2017 and 2016, respectively.

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 77,760	$ 78,359
Prior service credit	(21,448)	(27,695)
Total	$ 56,312	$ 50,664

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Noncurrent regulatory assets	$ 56,312	$ 50,664
Measurement date	Dec. 31, 2017	Dec. 31, 2016

	2017	2016
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	3.62%	4.13%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial: Pre-65	7.00%	5.50%
Health care costs trend rate — initial: Post-65	5.50%	5.50%

Beginning with the Dec. 31 2017 measurement, Xcel Energy Inc. and PSCo separated its initial medical trend assumption for pre-Medicare (Pre-65) and post-Medicare (Post-65) claims costs of 7.0 percent and 5.5 percent, respectively, in order to reflect different short-term expectations based on recent experience differences. The ultimate trend assumption remained at 4.5 percent for both Pre-65 and Post-65 claims costs as similar long-term trend rates are expected for both populations. The period until the ultimate rate is reached is five years. Xcel Energy Inc. and PSCo base the 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 increases experienced by the retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on PSCo:

	One-Percentage Point	
(Thousands of Dollars)	Increase	Decrease
APBO	$ 41,665	$ (35,254)
Service and interest components	1,837	(1,555)

Cash Flows **—** The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes PSCo, contributed $20 million, $18 million and $18 million during 2017, 2016 and 2015, respectively, of which $5 million, $5 million and $6 million were attributable to PSCo. Xcel Energy expects to contribute approximately $12 million during 2018, of which amounts attributable to PSCo will be zero.

Plan Amendments **—** In 2017 and 2016 there were no plan amendments made which affected the projected benefit obligation.

Benefit Costs — The components of PSCo's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2017	2016	2015
Service cost	$ 767	$ 768	$ 928
Interest cost	16,765	18,070	17,498
Expected return on plan assets	(21,905)	(22,299)	(23,803)
Amortization of prior service credit	(6,247)	(6,247)	(6,247)
Amortization of net loss	3,843	1,931	2,475
Net periodic postretirement benefit credit	$ (6,777)	$ (7,777)	$ (9,149)

	2017	2016	2015
Significant Assumptions Used to Measure Costs:			
Discount rate	4.13%	4.65%	4.08%
Expected average long-term rate of return on assets	5.80	5.80	5.80

In addition to the benefit costs in the table above, for the postretirement health care plans sponsored by Xcel Energy Inc., costs are allocated to PSCo based on Xcel Energy Services Inc. employees' labor costs.

Projected Benefit Payments

The following table lists PSCo's projected benefit payments for the pension and postretirement benefit plans:

(Thousands 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
2018	$ 83,036	$ 32,186	$ 2,074	$ 30,112
2019	81,698	32,454	2,192	30,262
2020	81,413	32,767	2,296	30,471
2021	82,021	32,737	2,404	30,333
2022	83,261	32,998	2,501	30,497
2023-2027	411,798	152,926	13,789	139,137

9. Other Income, Net

Other income, net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2017	2016	2015
Interest income	$ 3,809	$ 1,860	$ 753
Other nonoperating income	6,383	2,241	2,408
Insurance policy expense	(340)	(281)	(197)
Other nonoperating expense	—	(3)	—
Other income, net	$ 9,852	$ 3,817	$ 2,964

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain 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. The three levels in the hierarchy are as follows:

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

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

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

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

Commodity derivatives — The 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.

Derivative Instruments Fair Value Measurements

PSCo 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* —** PSCo 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.

At Dec. 31, 2017, accumulated other comprehensive losses related to interest rate derivatives included $1.2 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

***Wholesale and Commodity Trading Risk* —** PSCo conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. PSCo's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

***Commodity Derivatives* —** PSCo 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, and vehicle fuel.

PSCo enters 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 OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. PSCo recorded no amounts to income related to the ineffectiveness of cash flow hedges for the year ended Dec. 31, 2017 and immaterial amounts for the year ended Dec. 31, 2016.

Additionally, PSCo 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.

The following table details the gross notional amounts of commodity forwards and options at Dec. 31:

(Amounts in Thousands) [(a)(b)]	**2017**	**2016**
MWh of electricity	22,260	6,283
MMBtu of natural gas	13,410	42,203

(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* —** PSCo continuously monitors the creditworthiness of the 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. Given this assessment, as well as an assessment of the impact of PSCo's own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

PSCo employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

PSCo's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2017, five of PSCo's 10 most significant counterparties for these activities, comprising $7.0 million or 16 percent of this credit exposure, had investment grade credit ratings from S&P's, Moody's or Fitch Ratings. Four of the 10 most significant counterparties, comprising $16.5 million or 37 percent of this credit exposure at Dec. 31, 2017 were not rated by these external agencies, but based on PSCo's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising $7.4 million or 17 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. Six of these significant counterparties are municipal or cooperative electric entities, or other utilities.

***Financial Impact of Qualifying Cash Flow Hedges* —** The impact of qualifying interest rate and vehicle fuel cash flow hedges on PSCo's accumulated other comprehensive loss, included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2017	2016	2015
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (22,780)	$ (23,836)	$ (23,878)
After-tax net unrealized losses related to derivatives accounted for as hedges	—	—	(30)
After-tax net realized losses on derivative transactions reclassified into earnings	1,005	1,056	72
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (21,775)	$ (22,780)	$ (23,836)

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2017, 2016 and 2015, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2017				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1,615 [(a)]	$ —	$ —
Total	$ —	$ —	$ 1,615	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 386 [(c)]
Natural gas commodity	—	(10,921)	—	1,933 [(d)]	(4,170) [(d)]
Total	$ —	$ (10,921)	$ —	$ 1,933	$ (3,784)

(Thousands of Dollars)	Year Ended Dec. 31, 2016 — Pre-Tax Fair Value Gains Recognized During the Period in: Accumulated Other Comprehensive Loss	Pre-Tax Fair Value Gains Recognized During the Period in: Regulatory (Assets) and Liabilities	Pre-Tax Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Pre-Tax Losses Reclassified into Income During the Period from: Regulatory Assets and (Liabilities)	Pre-Tax Losses Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1,618 [a]	$ —	$ —
Vehicle fuel and other commodity	—	—	86 [b]	—	—
Total	$ —	$ —	$ 1,704	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ (257) [c]
Natural gas commodity	—	2,051	—	10,292 [d]	(5,832) [d]
Total	$ —	$ 2,051	$ —	$ 10,292	$ (6,089)

(Thousands of Dollars)	Year Ended Dec. 31, 2015 — Pre-Tax Fair Value Losses Recognized During the Period in: Accumulated Other Comprehensive Loss	Pre-Tax Fair Value Losses Recognized During the Period in: Regulatory (Assets) and Liabilities	Pre-Tax Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Pre-Tax Losses Reclassified into Income During the Period from: Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 54 [a]	$ —	$ —
Vehicle fuel and other commodity	(50)	—	57 [b]	—	—
Total	$ (50)	$ —	$ 111	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 364 [c]
Natural gas commodity	—	(10,635)	—	10,158 [d]	(7,620) [d]
Total	$ —	$ (10,635)	$ —	$ 10,158	$ (7,256)

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are 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.

(d) Certain derivatives are utilized to mitigate natural gas price risk for electric generation and are recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset as appropriate. Amounts for the year ended Dec. 31, 2017 included $0.4 million of settlement gains and amounts for the years ended Dec. 31, 2016 and 2015 included $0.2 million and $1.1 million, respectively, 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. The remaining settlement losses for the years ended Dec. 31, 2017, 2016 and 2015 relate to natural gas operations and are 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.

PSCo had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2017, 2016 and 2015. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features **—** Contract provisions for derivative instruments that PSCo enters into, 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 PSCo'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 that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. At Dec. 31, 2017 and 2016, there were no derivative instruments in a material 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 PSCo's ability to fulfill its contractual obligations is reasonably expected to be impaired. PSCo had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2017 and 2016.

Recurring Fair Value Measurements **—** The following table presents, for each of the fair value hierarchy levels, PSCo's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2017:

	Dec. 31, 2017					
	Fair Value					
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Counterparty Netting [(b)]**	**Total**
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 528	$ 4,488	$ 12	$ 5,028	$ (3,554)	$ 1,474
Natural gas commodity	—	18	—	18	(10)	8
Total current derivative assets	$ 528	$ 4,506	$ 12	$ 5,046	$ (3,564)	1,482
PPAs [(a)]						1,715
Current derivative instruments						$ 3,197
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 1,541	$ —	$ 1,541	$ (563)	$ 978
Total noncurrent derivative assets	$ —	$ 1,541	$ —	$ 1,541	$ (563)	978
PPAs [(a)]						31
Noncurrent derivative instruments						$ 1,009
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$ 446	$ 4,285	$ 6	$ 4,737	$ (3,431)	$ 1,306
Natural gas commodity	—	1,016	—	1,016	(10)	1,006
Total current derivative liabilities	$ 446	$ 5,301	$ 6	$ 5,753	$ (3,441)	2,312
PPAs [(a)]						5,036
Current derivative instruments						$ 7,348
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ —	$ 1,362	$ —	$ 1,362	$ (563)	$ 799
Total noncurrent derivative liabilities	$ —	$ 1,362	$ —	$ 1,362	$ (563)	799
PPAs [(a)]						$ 2,669
Noncurrent derivative instruments						$ 3,468

(a) During 2006, PSCo 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.

(b) PSCo 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 at Dec. 31, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return or reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents, for each of the fair value hierarchy levels, PSCo's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2016:

	Dec. 31, 2016					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 1,124	$ 5,453	$ —	$ 6,577	$ (5,137)	$ 1,440
Natural gas commodity	—	7,778	—	7,778	—	7,778
Total current derivative assets	$ 1,124	$ 13,231	$ —	$ 14,355	$ (5,137)	9,218
PPAs [(a)]						1,716
Current derivative instruments						$ 10,934
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 1,652	$ —	$ 1,652	$ —	$ 1,652
Total noncurrent derivative assets	$ —	$ 1,652	$ —	$ 1,652	$ —	1,652
PPAs [(a)]						1,746
Noncurrent derivative instruments						$ 3,398
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$ 1,386	$ 5,357	$ 22	$ 6,765	$ (5,137)	$ 1,628
Total current derivative liabilities	$ 1,386	$ 5,357	$ 22	$ 6,765	$ (5,137)	1,628
PPAs [(a)]						5,160
Current derivative instruments						$ 6,788
Noncurrent derivative liabilities						
PPAs [(a)]						$ 7,828
Noncurrent derivative instruments						$ 7,828

(a) During 2006, PSCo 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.

(b) PSCo 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 at Dec. 31, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral of or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

There were immaterial gains recognized in earnings for the year ended Dec. 31, 2017 and immaterial losses recognized in earnings for the year ended Dec. 31, 2016 for level 3 commodity trading derivatives. There were no changes in Level 3 recurring fair value measurements for the year ended Dec. 31, 2015.

PSCo recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2017, 2016 and 2015.

Fair Value of Long-Term Debt

As of Dec. 31, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

	2017		2016	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 4,608,275	$ 5,024,840	$ 4,216,206	$ 4,491,570

The fair value of PSCo's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2017 and 2016, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

11. Rate Matters

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on retail customer rates are subject to regulatory approval. PSCo is in the process of quantifying the rate impacts of the TCJA and are being addressed in several regulatory proceedings focused on retail base rate impacts, which include the following:

- Colorado Statewide TCJA Proceeding — On Jan. 31, 2018, the CPUC opened a statewide TCJA proceeding and ordered deferred accounting for all investor-owned utilities. On Feb. 21, 2017, PSCo filed a response with the CPUC related to the deferred accounting order and statewide TCJA proceeding, addressing the estimated impacts along with other considerations given PSCo's pending natural gas and electric rate cases.

- Colorado 2017 Multi-Year Natural Gas Rate Case — On Feb. 14, 2018, the ALJ approved PSCo and CPUC Staff's non-unanimous settlement agreement which addresses the impacts of the TCJA in 2018. This settlement agreement includes a \$20 million reduction to provisional rates effective March 1, 2018, with future true-ups to be determined later in 2018 once a full analysis of the comprehensive impacts of tax reform is performed, including any outcomes associated with statewide proceeding. The final true-up would provide customers the full net benefit of the TCJA effective Jan. 1, 2018.

- Colorado 2017 Multi-Year Electric Rate Case — On Feb. 16, 2018, the CPUC denied the proposed settlement agreement between PSCo and several intervenors, in favor of the state TCJA proceeding. In the second quarter of 2018, PSCo plans to file a revised rate request that will include the impacts of the TCJA. Provisional rates, subject to refund with interest, are expected to be effective June 1, 2018. The appropriate test year and the final approved revenue requirement will be determined in the pending rate case, discussed below. PSCo expects to defer the TCJA net benefits for the first five months of 2018, prior to provisional rates.

The CPUC is expected to rule on the regulatory treatment of the TCJA, the natural gas rate case and the electric rate case later in 2018.

Pending Regulatory Proceedings — CPUC

Colorado 2017 Multi-Year Electric Rate Case — In October 2017, PSCo filed a multi-year request with the CPUC seeking to increase electric rates approximately \$245 million over four years. The request, summarized below, is based on FTY ending Dec. 31, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	2021	Total
Revenue request	\$ 74	\$ 75	\$ 60	\$ 36	\$ 245
CACJA revenue conversion to base rates [(a)]	90	—	—	—	90
TCA revenue conversion to base rates [(a)]	43	—	—	—	43
Total [(b)]	\$ 207	\$ 75	\$ 60	\$ 36	\$ 378
Expected year-end rate base (billions of dollars) [(b)]	\$ 6.8	\$ 7.1	\$ 7.3	\$ 7.4	

(a) The roll-in of the TCA and CACJA rider revenues into base rates will not have an impact on customer bills or revenue as these costs are already being recovered through a rider. Transmission investments for 2019-2021 will be recovered through the TCA rider.

(b) This base rate request does not include the impacts of the RESA and ECA for the Rush Creek wind investments or the proposed CEP.

Key dates in the procedural schedule are as follows:

- Supplemental direct testimony — April 16, 2018;
- Answer testimony — May 31, 2018;
- Rebuttal and cross-answer testimony — July 10, 2018;
- Hearings — Aug. 21 - 31, 2018; and
- Statement of position — Sept. 28, 2018.

Interim rates, subject to refund and interest, are to be effective on June 1, 2018. PSCo also proposed a stay-out provision and earnings test through 2021. On Jan. 31, 2018, the CPUC ordered deferred accounting for the impacts of TCJA and opened a statewide TCJA proceeding, as discussed above. In the second quarter of 2018, PSCo plans to file a revised rate request that will include the impacts of the TCJA. The CPUC is expected to rule on the regulatory treatment of the TCJA and the electric rate case later in 2018.

Colorado 2017 Multi-Year Natural Gas Rate Case — In June 2017, PSCo filed a multi-year request with the CPUC seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, is based on FTYs, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	Total
Revenue request	$ 63	$ 33	$ 43	$ 139
PSIA revenue conversion to base rates [(a)]	—	94	—	94
Total	$ 63	$ 127	$ 43	$ 233
Expected year-end rate base (billions of dollars) [(b)]	$ 1.5	$ 2.3	$ 2.4	

(a) The roll-in of PSIA rider revenue into base rates will not have an impact on customer bills or revenue as these costs are already being recovered through the rider. The recovery of incremental PSIA related investments in 2019 and 2020 are included in the base rate request.

(b) The additional rate base in 2019 predominantly reflects the roll-in of capital associated with the PSIA rider.

In October 2017, several parties filed answer testimony. The CPUC Staff (Staff) and the OCC, recommended a single 2016 HTY, based on an average 13-month rate base, and opposed a multi-year request. The Staff and OCC recommended an equity capital structure of 48.73 percent and 51.2 percent, respectively. Both the Staff and the OCC recommended the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through base rates, subject to a future rate case. The final positions of the Staff and OCC provide for a recommended 2018 rate increase of approximately $30 million and $39 million, respectively.

In December 2017, hearings before an ALJ were held and the evidentiary record for the case was closed. Provisional rates, subject to refund, were implemented on Jan. 1, 2018. As discussed above, PSCo and the CPUC Staff filed a non-unanimous settlement agreement to address the impacts of the TCJA on rates to be effective in 2018, which was approved by the ALJ. On Jan. 31, 2018, the CPUC ordered deferred accounting for the impacts of TCJA and opened a statewide TCJA proceeding, as discussed above. The CPUC is expected to rule on the regulatory treatment of the TCJA and the natural gas rate case later in 2018.

Annual Electric Earnings Test — PSCo must share with customers earnings that exceed the authorized ROE of 9.83 percent for 2015 through 2017, as part of an annual earnings test. PSCo estimates the 2017 earnings test will not result in a customer refund obligation. PSCo will file its 2017 earnings test with the CPUC in April 2018. The final sharing obligation, if any, will be based on the CPUC approved tariff and could vary from the current estimate.

Electric, Purchased Gas and Resource Adjustment Clauses

DSM and the DSMCA riders — Energy efficiency and DSM costs are recovered through a combination of the DSMCA riders and base rates. DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are trued-up in the following year. Performance incentives are awarded in the year following plan achievements. PSCo is able to earn $5 million upon reaching its annual savings goal along with an incentive on five percent of net economic benefits up to a maximum annual incentive of $30 million. In 2017, PSCo earned an electric and natural gas DSM incentive of $11 million and $3 million, respectively, for achieving its 2016 electric and natural gas savings goals. For 2018, the electric energy savings goal is 400 GWh with a spending limit of $84 million.

12. Commitments and Contingencies

Commitments

Capital Commitments **—** PSCo has made commitments in connection with a portion of its projected capital expenditures. PSCo’s capital commitments primarily relate to the following major projects:

Advanced Grid Intelligence and Security Initiative — PSCo is pursuing projects to update and advance its electric distribution grid to increase reliability and security standards, meet customer expectations, offer additional customer choice and control over energy usage and implement new rate structures.

Rush Creek Wind Farm — PSCo has gained approval to build, own and operate a 600 MW wind generation facility and proposed transmission line in Colorado.

Gas Transmission Integrity Management Programs — PSCo is proactively identifying and addressing the safety and reliability of natural gas transmission pipelines. The pipeline integrity efforts include primarily pipeline assessment and maintenance projects.

Electric Distribution Integrity Management Programs — PSCo is assessing aging infrastructure for distribution assets and replacing worn components to increase system performance.

Fuel Contracts — PSCo has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal and natural gas requirements. These contracts expire in various years between 2018 and 2060. PSCo is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for PSCo under these contracts as of Dec. 31, 2017, are as follows:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2018	$ 160	$ 344	$ 114
2019	97	286	112
2020	69	275	111
2021	37	278	109
2022	38	126	109
Thereafter	184	57	605
Total	$ 585	$ 1,366	$ 1,160

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. PSCo's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

PPAs — PSCo has entered into PPAs with other utilities and energy suppliers with expiration dates through 2034 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting contract obligations, including plant availability requirements. 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 $25 million, $44 million and $70 million in 2017, 2016 and 2015, respectively. At Dec. 31, 2017, the estimated future payments for capacity that PSCo is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity
2018	$ 22
2019	12
2020	4
2021	4
2022	4
Thereafter	14
Total	$ 60

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — PSCo leases a variety of equipment and facilities. Three of these leases are accounted for as capital leases. The assets and liabilities at the inception of a capital lease are recorded at the lower of fair market value or the present value of future lease payments and are amortized over the term of the contract.

WYCO is a joint venture between Xcel Energy Inc. and Colorado Interstate Gas Company, LLC (CIG) to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy Inc. has a 50 percent ownership interest in WYCO, and PSCo has no direct ownership interest. WYCO generally leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had $124 million and $127 million of capital lease obligations as of Dec. 31, 2017 and 2016, respectively.

PSCo records amortization for its capital leases as cost of natural gas sold and transported on the consolidated statements of income. Total amortization expenses under capital lease assets were approximately $5 million, $8 million, and $8 million for 2017, 2016 and 2015, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Gas storage facilities	$ 200.5	$ 200.5
Gas pipeline	20.7	20.7
Property held under capital leases	221.2	221.2
Accumulated depreciation	(70.6)	(65.3)
Total property held under capital leases, net	$ 150.6	$ 155.9

The remainder of the leases, primarily for office space, railcars, generating facilities, vehicles, aircraft and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations were approximately $109 million, $118 million and $130 million for 2017, 2016 and 2015, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of $96 million, $102 million and $114 million in 2017, 2016 and 2015, respectively, recorded to electric fuel and purchased power expenses.

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

(Millions of Dollars)	Operating Leases	PPA [(a) (b)] Operating Leases	Total Operating Leases	Capital Leases
2018	$ 10	$ 96	$ 106	$ 25
2019	10	97	107	25
2020	10	98	108	25
2021	9	99	108	24
2022	8	87	95	21
Thereafter	34	394	428	442
Total minimum obligation				562
Interest component of obligation				(411)
Present value of minimum obligation				$ 151

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2034.

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

PPAs — Under certain PPAs, PSCo purchases power from independent power producing entities for which PSCo is required to reimburse natural gas fuel costs, or to participate in tolling arrangements under which PSCo procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the independent power producing entity.

PSCo has determined that certain independent power producing entities are variable interest entities. PSCo is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

PSCo has evaluated each of these variable interest entities 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. PSCo has 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. PSCo had approximately 1,571 MW of capacity under long-term PPAs at both Dec. 31, 2017 and 2016 with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2032.

Environmental Contingencies

PSCo has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, PSCo believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, PSCo is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for PSCo, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, PSCo would be required to recognize an expense.

***Site Remediation* —** Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. PSCo may sometimes pay all or a portion of the cost to remediate sites where past activities of PSCo or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by PSCo, its predecessors, or other entities; and third-party sites, such as landfills, for which PSCo is alleged to be a PRP that sent wastes to that site.

***Other MGP, Landfill or Disposal Sites* —** PSCo is currently involved in investigating and/or remediating several MGP, landfill or other disposal sites. PSCo has identified three sites where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities that are underway. PSCo anticipates that these investigation or remediation activities will continue through at least 2018. PSCo had accrued an immaterial amount and $2 million for all of these sites as of Dec. 31, 2017 and 2016, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. PSCo anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

***Asbestos Removal* —** Some of PSCo's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. PSCo has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Coal Ash Regulation — PSCo'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 a final rule regulating the management, storage, and disposal of coal combustion residuals (CCRs) as a nonhazardous waste (CCR Rule). Industry and environmental non-governmental organizations sought judicial review of the final CCR Rule, but a final decision has not been issued in that litigation. The EPA announced in late 2017 its intent to revise the CCR Rule. It is anticipated that the EPA will publish the revised rule in the first quarter of 2018.

Under the CCR Rule, utilities were required to complete groundwater sampling around their CCR landfills and surface impoundments and to analyze the results by early 2018 to determine if there were any statistically significant increases (SSIs) above background levels of certain constituents in the groundwater. PSCo has identified SSIs at several sites. Going forward, PSCo will either conduct additional groundwater sampling to determine whether another source besides plant operations is impacting groundwater and/or to determine if corrective action is needed. Several PSCo sites where SSIs were identified were already undergoing cessation of coal operations and closure of the on-site coal units and therefore no further corrective action is expected at those sites.

Until a final decision is reached in the litigation, the EPA publishes its revised rule, and PSCo completes additional groundwater sampling, it is uncertain what impact, if any, there will be on the operations, financial position or cash flows of PSCo. PSCo believes that any associated costs would be recoverable through regulatory mechanisms.

Federal CWA Waters of the United States Rule — In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) published a final rule that significantly expanded the types of water bodies regulated under the CWA and broadened the scope of waters subject to federal jurisdiction. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule and subsequently ruled that it, rather than the federal district courts, had jurisdiction over challenges to the rule. In January 2017, the U.S. Supreme Court agreed to resolve the dispute as to which court should hear challenges to the rule. A ruling is expected in 2018.

In February 2017, President Trump issued an executive order requiring the EPA and the Corps to review and revise the final rule. On June 27, 2017, the agencies issued a proposed rule that rescinds the final rule and reinstates the prior definition of "Water of the U.S." The agencies are also undertaking a rulemaking to develop a new definition of "Waters of the U.S."

Federal CWA Effluent Limitations Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020 while the agency conducts a rulemaking process to potentially revise the effluent limitations and pretreatment standards for these waste streams.

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 adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). PSCo does not anticipate the cost of compliance will have a material impact on its results of operations, financial position or cash flows.

Air

GHG Emission Standard for Existing Sources (CPP) — In 2015, the EPA issued its final CPP rule for existing power plants. Among other things, the CPP requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA's state-specific interim and final emission performance targets.

The CPP was challenged by multiple parties in the D.C. Circuit Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. The stay will remain in effect until the D.C. Circuit Court reaches its decision and the U.S. Supreme Court either declines to review the lower court's decision or reaches a decision of its own.

In March 2017, President Trump signed an executive order requiring the EPA Administrator to review the CPP rule and if appropriate publish proposed rules suspending, revising or rescinding it. Accordingly, the EPA requested that the D.C. Circuit Court hold the litigation in abeyance until the EPA completes its work under the executive order. The D.C. Circuit granted the EPA's request and is holding the litigation in abeyance, while considering briefs by the parties on whether the court should remand the challenges to the EPA rather than holding them in abeyance, determining whether and how the court continues or ends the stay that currently applies to the CPP.

In October 2017, the EPA published a proposed rule to repeal the CPP, based on an analysis that the CPP exceeds the EPA's statutory authority under the CAA. In the proposal, the EPA stated it has not yet determined whether it will promulgate a new rule to regulate GHG emissions from existing EGUs. In December 2017, the EPA issued an Advanced Notice of Proposed Rulemaking to take and consider comments on whether to issue a future rule and what such a rule should include.

Implementation of the NAAQS for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010, and evaluated areas in in three phases. In December 2017, the EPA adopted a final rule that completed its initial designations of areas attaining or not attaining the standard. The EPA's final actions designate all areas near PSCo's generating plants as meeting the SO_2 NAAQS with one exception. In June 2016, the EPA issued final designations which found the area near the Pawnee plant is "unclassifiable." Since the 2016 "unclassifiable" designation, the Colorado Department of Public Health and Environment has prepared and submitted air dispersion modeling to the EPA demonstrating that the area near the Pawnee plant meets the SO_2 NAAQS. The EPA has not yet completed its evaluation of the Pawnee plant.

Revisions to the NAAQS for Ozone — In 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In November 2017, the EPA published final designations of areas that meet the 2015 ozone standard. Xcel Energy meets the 2015 ozone standard in all areas where its generating units operate, except for the Denver Metropolitan Area. PSCo's scheduled retirement of coal fired plants in Denver that began in 2011 and was completed in August 2017, should help in any plan to mitigate non-attainment. The EPA has not yet taken final action on the designation, but notified the State of Colorado in December 2017 that it intends to designate the parts of the Denver Metropolitan Area that currently do not attain the 2008 ozone standards as also not attaining the more stringent 2015 ozone standard.

Asset Retirement Obligations

Recorded AROs **—** AROs have been recorded for property related to the following: electric production (steam, wind, other and hydro), electric distribution and transmission, natural gas production, natural gas transmission and distribution, natural gas storage, thermal and common general property. The electric production obligations include asbestos, processed water and ash-containment facilities, radiation sources, storage tanks and control panels. The asbestos recognition associated with electric production includes certain specific plants. The AROs recorded for PSCo steam and other production relate to processed water and ash-containment facilities such as ash ponds, evaporation ponds and solid waste landfills. PSCo has also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract.

PSCo recognized AROs for the retirement costs of natural gas mains and lines and for the retirement of above ground gas gathering equipment, impoundments at gas extraction sites and wells related to gas storage facilities. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment, which consists of obligations associated with polychlorinated biphenyl, mineral oil, lithium batteries, mercury and street lighting lamps. The common general ARO includes obligations related to storage tanks.

A reconciliation of PSCo's AROs for the years ended Dec. 31, 2017 and 2016 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2017	Liabilities Settled [(a)]	Accretion	Cash Flow Revisions [(b)]	Ending Balance Dec. 31, 2017 [(c)]
Electric plant					
Steam and other production ash containment	$ 72,600	$ (12,068)	$ 3,159	$ 9,573	$ 73,264
Steam, hydro, and other production asbestos	40,450	(12,047)	1,917	(458)	29,862
Electric distribution	7,669	—	274	—	7,943
Wind production	2,072	—	20	—	2,092
Other	1,520	(204)	66	—	1,382
Natural gas plant					
Gas transmission and distribution	160,719	—	6,649	61,503	228,871
Other	4,080	(354)	159	—	3,885
Common and other property					
Common miscellaneous	453	—	17	—	470
Total liability	$ 289,563	$ (24,673)	$ 12,261	$ 70,618	$ 347,769

(a) The liabilities settled relate to asbestos abatement projects, the closure of certain ash containment facilities, and removal and proper disposal of storage tanks and other above ground equipment.

(b) In 2017, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the gas transmission and distribution AROs were mainly related to increased labor costs.

(c) There were no ARO liabilities recognized during the year ended Dec. 31, 2017.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2016	Liabilities Recognized	Accretion	Cash Flow Revisions [(a)]	Ending Balance Dec. 31, 2016 [(b)]
Electric plant					
Steam, hydro, and other production asbestos	$ 38,676	$ —	$ 1,877	$ (103)	$ 40,450
Steam and other production ash containment	70,767	—	3,078	(1,245)	72,600
Wind production	1,992	—	19	61	2,072
Electric distribution	1,130	—	45	6,494	7,669
Other	1,054	214	46	206	1,520
Natural gas plant					
Gas transmission and distribution	122,168	—	5,009	33,542	160,719
Other	3,925	—	155	—	4,080
Common and other property					
Common miscellaneous	796	—	28	(371)	453
Total liability	$ 240,508	$ 214	$ 10,257	$ 38,584	$ 289,563

(a) In 2016, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the gas transmission and distribution AROs were mainly related to increased miles of gas mains.

(b) There were no ARO liabilities settled during the year ended Dec. 31, 2016.

Indeterminate AROs — Outside of the known and recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of PSCo's facilities, but no confirmation or measurement of the amount of asbestos or cost of removal could be determined as of Dec. 31, 2017. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — PSCo records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities that are recovered currently in rates. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over time, PSCo has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2017 and 2016 were $346 million and $367 million, respectively.

Legal Contingencies

PSCo is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on PSCo's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

Line Extension Disputes — In December 2015, Development Recovery Company (DRC) filed a lawsuit 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 entered into by PSCo and various developers. The dispute involves claims by over fifty developers. In May 2016, the Denver District Court granted PSCo's motion to dismiss the lawsuit, concluding that jurisdiction over this dispute resides with the CPUC. In June 2016, DRC appealed the Denver District Court's dismissal of the lawsuit, and the Colorado Court of Appeals affirmed the lower court decision in favor of PSCo. In July 2017, DRC filed a petition to appeal the decision with the Colorado Supreme Court. In February 2018, the Colorado Supreme Court denied DRC's petition effectively terminating this litigation.

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. Dates for this proceeding have not been scheduled.

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. Also, if a loss were sustained, PSCo believes it would be allowed to recover these costs through traditional regulatory mechanisms. The amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

Other Contingencies

See Note 11 for further discussion.

13. Regulatory Assets and Liabilities

PSCo's consolidated financial statements are prepared in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, 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. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of PSCo no longer allow for the application of regulatory accounting guidance under GAAP, PSCo would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the consolidated balance sheets of PSCo at Dec. 31, 2017 and 2016 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2017		Dec. 31, 2016	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations [a]	8	Various	$ 28,010	$ 565,241	$ 27,270	$ 568,258
Recoverable deferred taxes on AFUDC recorded in plant [b]	1	Plant lives	—	86,966	—	151,022
Net AROs [c]	1, 12	Plant lives	—	80,476	—	78,050
Depreciation differences	1	One to fourteen years	19,835	69,428	15,363	90,426
Excess deferred taxes - TCJA	7	Various	—	53,937	—	—
Purchased power contract costs	12	Term of related contract	1,261	28,009	1,035	29,029
Property tax		Pending rate cases	—	16,047	9,393	1,653
Gas pipeline inspection costs	12	One to two years	1,791	7,743	—	4,405
Conservation programs [d]	1, 11	One to two years	6,942	5,528	9,262	6,986
Losses on reacquired debt	4	Term of related debt	1,203	4,916	1,203	6,120
Contract valuation adjustments [e]	10	Term of related contract	6,022	2,638	3,444	6,082
Other		Various	12,273	29,329	36,813	16,398
Total regulatory assets			$ 77,337	$ 950,258	$ 103,783	$ 958,429

(a) Includes $3.4 million and $4.2 million of regulatory assets related to the nonqualified pension plan, of which $0.3 million and $0.4 million is included in the current asset at Dec. 31, 2017 and 2016, respectively.

(b) Includes a write-down of $75.9 million as a result of the revaluation of deferred tax gross up at the new federal tax rate at Dec. 31, 2017.

(c) Includes amounts recorded for future recovery of AROs.

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

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

The components of regulatory liabilities shown on the consolidated balance sheets of PSCo at Dec. 31, 2017 and 2016 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2017		Dec. 31, 2016	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Excess deferred taxes - TCJA [a]	7	Various	$ —	$1,445,079	$ —	$ —
Plant removal costs	1, 12	Plant lives	—	346,174	—	367,440
Renewable resources and environmental initiatives	11, 12	Various	—	56,153	3,600	67,728
Investment tax credit deferrals	1, 7	Various	—	17,088	—	18,797
Deferred income tax adjustment	1	Various	—	16,301	—	16,260
Deferred electric, natural gas and steam production costs	1	Less than one year	29,078	—	35,123	—
Conservation programs [b]	1, 11	Less than one year	21,168	—	24,077	—
Other		Various	15,880	52,693	38,310	42,708
Total regulatory liabilities [c]			$ 66,126	$1,933,488	$ 101,110	$ 512,933

(a) Primarily relates to the revaluation of recoverable/regulated plant ADIT and $49.6 million revaluation impact of non-plant ADIT at Dec. 31, 2017.

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

(c) Revenue subject to refund of $0 million and $2.4 million for 2017 and 2016, respectively, is included in other current liabilities.

At Dec. 31, 2017 and 2016, approximately $44 million and $28 million of PSCo's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes certain expenditures associated with property taxes and renewable resources and environmental initiatives.

14. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31, 2017 and 2016 were as follows:

	Year Ended Dec. 31, 2017		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (22,780)	$ (220)	$ (23,000)
Other comprehensive loss before reclassifications	—	(5)	(5)
Losses reclassified from net accumulated other comprehensive loss	1,005	5	1,010
Net current period other comprehensive income	1,005	—	1,005
Adoption of ASU No. 2018-02 [(a)]	(4,690)	(47)	(4,737)
Accumulated other comprehensive loss at Dec. 31	$ (26,465)	$ (267)	$ (26,732)

(a) In 2017, PSCo 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. For further information, see Note 2.

	Year Ended Dec. 31, 2016		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (23,836)	$ —	$ (23,836)
Other comprehensive loss before reclassifications	—	(223)	(223)
Losses reclassified from net accumulated other comprehensive loss	1,056	3	1,059
Net current period other comprehensive income (loss)	1,056	(220)	836
Accumulated other comprehensive loss at Dec. 31	$ (22,780)	$ (220)	$ (23,000)

Reclassifications from accumulated other comprehensive loss for the years ended Dec. 31, 2017 and 2016 were as follows:

	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Thousands of Dollars)	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Losses (gains) on cash flow hedges:		
Interest rate derivatives	$ 1,615 [(a)]	$ 1,618 [(a)]
Vehicle fuel derivatives	— [(b)]	86 [(b)]
Total, pre-tax	1,615	1,704
Tax benefit	(610)	(648)
Total, net of tax	1,005	1,056
Defined benefit pension and postretirement losses (gains):		
Amortization of net losses	9 [(c)]	5 [(c)]
Total, pre-tax	9	5
Tax benefit	(4)	(2)
Total, net of tax	5	3
Total amounts reclassified, net of tax	$ 1,010	$ 1,059

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 8 for details regarding these benefit plans.

15. Segments and Related Information

Operating results from the regulated electric utility and regulated natural gas utility are each separately and regularly reviewed by PSCo's chief operating decision maker. PSCo evaluates performance 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.

PSCo has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- PSCo's regulated electric utility segment generates electricity which is transmitted and distributed in Colorado. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes PSCo's wholesale commodity and trading operations.
- PSCo's regulated natural gas utility segment transports, stores and distributes natural gas in portions of Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services and nonutility real estate activities.

Asset and capital expenditure information is not provided for PSCo's reportable segments because as an integrated electric and natural gas utility, PSCo operates significant assets that are not dedicated to a specific business segment, and 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.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2017					
Operating revenues [(a)]	$ 3,003,808	$ 995,214	$ 43,487	$ —	$ 4,042,509
Intersegment revenues	288	344	—	(632)	—
Total revenues	$ 3,004,096	$ 995,558	$ 43,487	$ (632)	$ 4,042,509
Depreciation and amortization	$ 353,560	$ 113,253	$ 4,702	$ —	$ 471,515
Interest charges and financing costs	138,565	40,214	508	—	179,287
Income tax expense (benefit)	243,604	18,398	(9,823)	—	252,179
Net income	370,636	107,822	15,661	—	494,119

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2016					
Operating revenues [(a)]	$ 3,049,352	$ 957,721	$ 40,723	$ —	$ 4,047,796
Intersegment revenues	275	110	—	(385)	—
Total revenues	$ 3,049,627	$ 957,831	$ 40,723	$ (385)	$ 4,047,796
Depreciation and amortization	$ 337,583	$ 101,663	$ 4,309	$ —	$ 443,555
Interest charges and financing costs	136,274	37,881	431	—	174,586
Income tax expense (benefit)	228,825	45,960	(867)	—	273,918
Net income	383,973	75,426	4,092	—	463,491

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2015					
Operating revenues [(a)]	$ 3,115,257	$ 1,006,666	$ 41,590	$ —	$ 4,163,513
Intersegment revenues	301	67	—	(368)	—
Total revenues	$ 3,115,558	$ 1,006,733	$ 41,590	$ (368)	$ 4,163,513
Depreciation and amortization	$ 311,122	$ 96,384	$ 4,161	$ —	$ 411,667
Interest charges and financing costs	136,397	34,935	576	—	171,908
Income tax expense (benefit)	234,873	44,192	(625)	—	278,440
Net income	391,257	74,267	1,278	—	466,802

(a) Operating revenues include $6 million, $13 million and $13 million of intercompany revenue for the years ended Dec. 31, 2017, 2016 and 2015, respectively. See Note 16 for further discussion of related party transactions by reportable segment.

16. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including PSCo. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. PSCo uses services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 4 for further discussion.

The table below contains significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Thousands of Dollars)	2017	2016	2015
Operating revenues:			
Electric	$ 1,436	$ 8,809	$ 8,632
Other	4,492	4,525	4,441
Operating expenses:			
Purchased power	2	56	—
Other operating expenses — paid to Xcel Energy Services Inc.	485,066	446,086	414,620
Interest expense	—	149	211
Interest income	—	—	45

Accounts receivable and payable with affiliates at Dec. 31 were:

	2017		2016	
(Thousands of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 7,738	$ —	$ 7,669	$ —
NSP-Wisconsin	61	—	974	—
SPS	279	—	745	—
Other subsidiaries of Xcel Energy Inc.	6,641	58,748	33	98,797
	$ 14,719	$ 58,748	$ 9,421	$ 98,797

17. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Thousands of Dollars)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$ 1,080,534	$ 930,916	$ 1,030,293	$ 1,000,766
Operating income	212,422	192,811	326,028	154,669
Net income	111,546	100,587	186,077	95,909

(Thousands of Dollars)	Quarter Ended March 31, 2016	June 30, 2016	Sept. 30, 2016	Dec. 31, 2016
Operating revenues	$ 1,057,841	$ 909,852	$ 1,059,177	$ 1,020,926
Operating income	223,190	180,629	315,605	170,197
Net income	115,874	87,344	173,607	86,666

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

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

PSCo maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in the 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 (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2017, based on an evaluation carried out under the supervision and with the participation of PSCo's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that PSCo's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in PSCo'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, PSCo's internal control over financial reporting. PSCo maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. PSCo 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, 2017 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, PSCo conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, PSCo 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.

In 2016, PSCo implemented the general ledger modules of a new enterprise resource planning system to improve certain financial and related transaction processes. PSCo implemented additional work management systems modules in 2017. PSCo updated its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting systems. PSCo does not believe that this implementation had an adverse effect on its internal control over financial reporting.

This annual report does not include an attestation report of PSCo's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PSCo's independent registered public accounting firm pursuant to the rules of the SEC that permit PSCo to provide only management's report in this annual report.

Item 9B — Other Information

None.

PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for PSCo in accordance with conditions set forth in general instructions I (1) (a) and (b) of Form 10-K for wholly-owned subsidiaries.

Item 10 — Directors, Executive Officers and Corporate Governance

Item 11 — Executive Compensation

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

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 2018 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

The information required by Item 14 of From 10-K is set forth under the heading "Independent Registered Public Accounting Firm - Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 3, 2018. Such information set forth under such heading is incorporated herein by this reference hereto.

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, 2017.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For the three years ended Dec. 31, 2017, 2016, and 2015.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2017, 2016, and 2015.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2017, 2016, and 2015.
	Consolidated Balance Sheets — As of Dec. 31, 2017 and 2016.
	Consolidated Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2017, 2016 and 2015.
	Consolidated Statements of Capitalization — As of Dec. 31, 2017 and 2016.
2.	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2017, 2016, and 2015.
3.	Exhibits

*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
t	Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

3.01*	Amended and Restated Articles of Incorporation dated July 15, 1998 (Exhibit 3.01 to Form 10-Q for the quarter ended Sept. 30, 2017 (file no. 001-03280)).
3.02*	By-Laws of PSCo as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 001-03280)).
4.01*	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 (Exhibit 4.34 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2017).
4.02*	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 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).
4.03*	Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no. 001-03280) dated Aug. 18, 2007).
4.04*	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 percent First Mortgage Bonds, Series No. 18 due 2018 and $300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).
4.05*	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 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).
4.06*	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 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 18, 2010 (file no. 001-03280)).
4.07*	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 percent First Mortgage Bonds, Series No. 22 due 2041 (Exhibit 4.01 to Form 8-K of PSCo dated Aug. 9, 2011 (file no. 001-03280)).
4.08*	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 percent First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).
4.09*	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 percent First Mortgage Bonds, Series No. 25 due 2023 and $250 million principal amount of 3.95 percent First Mortgage Bonds, Series No. 26 due 2043 (Exhibit 4.01 to Form 8-K of PSCo dated March 26, 2013 (file no. 001-03280)).

4.10*	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 percent First Mortgage Bonds, Series No. 27 due 2044. (Exhibit 4.01 to Form 8-K of PSCo dated March 10, 2014 (file no. 001-03280)).
4.11*	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 percent First Mortgage Bonds, Series No. 28 due 2025. (Exhibit 4.01 to Form 8-K of PSCo dated May 12, 2015 (file no. 001-03280)).
4.12*	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 percent First Mortgage Bonds, Series No. 29 due 2046. (Exhibit 4.01 to Form 8-K of PSCo dated June 13, 2016 (file no. 001-03280)).
4.13*	Supplemental Indenture No. 27 dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as Trustee, creating $400 million principal amount of 3.80 percent First Mortgage Bonds, Series No. 30 due 2047. (Exhibit 4.01 to Form 8-K of PSCo dated June 19, 2017 (file no. 001-03280)).
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.03*+	Xcel Energy Inc. Non-Employee Directors' Deferred Compensation Plan as amended and restated on Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.06*	Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
10.07*+	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.08*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.09*+	Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 6, 2010).
10.10*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 6, 2010).
10.11*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed Apr. 5, 2011).
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.13*+	First Amendment effective Nov. 29, 2011 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.14*+	Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.18 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.15*+	First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.16*+	Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.17*+	First Amendment dated May 21, 2013 to the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.21 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.18*+	Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.22 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.19*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).

10.20*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2015).
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. (As First Effective May 20, 2015) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.02 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.22*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.03 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
10.23*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement. (Exhibit 10.28 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
10.24*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.29 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
10.25*+	Fifth Amendment dated May 3, 2016 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June 30, 2016).
10.26*	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. (Exhibit 99.03 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
10.27*+	Third Amendment dated Sept. 30, 2016 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2016).
10.28*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.27 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2016).
10.29*+	Fourth Amendment to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.1 to Form 10-Q of Xcel Energy for the quarter ended Sept. 30, 2017 (file no. 001-03034)).
10.30*+	Sixth Amendment dated Feb. 22, 2018 to Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.30 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2017.

12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
23.01	Consent of Independent Registered Public Accounting Firm.
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.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from PSCo’s Annual Report on Form 10-K for the year ended Dec. 31, 2017 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 Stockholder’s Equity, (vi) the Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, and (ix) Schedule II.

SCHEDULE II

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2017, 2016 AND 2015
(amounts in thousands)

	Balance at Jan. 1	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts [(a)]	Deductions from Reserves [(b)]	Balance at Dec. 31
Allowance for bad debts:					
2017	$ 19,612	$ 14,303	$ 3,968	$ 18,277	$ 19,606
2016	20,122	14,121	4,447	19,078	19,612
2015	23,122	13,052	5,175	21,227	20,122

(a) Recovery of amounts previously written off.

(b) Deductions relate primarily to bad debt write-offs.

Item 16 — Form 10-K Summary

None.

SIGNATURES

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

	PUBLIC SERVICE COMPANY OF COLORADO
Feb. 23, 2018	/s/ ROBERT C. FRENZEL
	Robert C. Frenzel Executive Vice President, Chief Financial Officer and Director (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	/s/ DAVID L. EVES
Ben Fowke Chairman, Chief Executive Officer and Director (Principal Executive Officer)	David L. Eves President and Director
/s/ ROBERT C. FRENZEL	/s/ JEFFREY S. SAVAGE
Robert C. Frenzel Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
/s/ MARVIN E. MCDANIEL, JR.	
Marvin E. McDaniel, Jr. Director	

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

PSCo has not sent, and does not expect to send, an annual report or proxy statement to its security holder.

Exhibit 12.01

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
STATEMENT OF COMPUTATION OF
RATIO OF EARNINGS TO FIXED CHARGES
(amounts in thousands, except ratio)

	Year Ended Dec. 31				
	2017	**2016**	**2015**	**2014**	**2013**
Earnings, as defined:					
Pretax income	$ 746,298	$ 737,409	$ 745,242	$ 698,779	$ 704,123
Add: Fixed charges	241,434	236,080	235,530	232,832	232,539
Total earnings, as defined	$ 987,732	$ 973,489	$ 980,772	$ 931,611	$ 936,662
Fixed charges, as defined:					
Interest charges	$ 190,694	$ 181,631	$ 177,430	$ 171,881	$ 173,602
Interest charges on life insurance policy borrowings	271	203	233	214	245
Interest component of leases	50,469	54,246	57,867	60,737	58,692
Total fixed charges, as defined	$ 241,434	$ 236,080	$ 235,530	$ 232,832	$ 232,539
Ratio of earnings to fixed charges	4.1	4.1	4.2	4.0	4.0

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-203664-04 on Form S-3 of our report dated February 23, 2018, relating to the consolidated financial statements and financial statement schedule of Public Service Company of Colorado and subsidiaries appearing in this Annual Report on Form 10-K of Public Service Company of Colorado for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2018

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Colorado;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 23, 2018

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Colorado;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 23, 2018

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Public Service Company of Colorado (PSCo) on Form 10-K for the year ended Dec. 31, 2017, as filed with the SEC on the date hereof (Form 10-K), each of the undersigned officers of PSCo certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PSCo as of the dates and for the periods expressed in the Form 10-K.

Date: Feb. 23, 2018

/s/ BEN FOWKE
Ben Fowke
Chairman, Chief Executive Officer and Director

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to PSCo and will be retained by PSCo and furnished to the SEC or its staff upon request.

Exhibit 99.01

Public Service Company of Colorado Cautionary Factors

The Private Securities Litigation Reform Act provides a “safe harbor” for forward-looking statements to encourage such disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of PSCo. These statements are based on management’s beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause PSCo’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where PSCo has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the Federal Energy Regulatory Commission and similar entities with regulatory oversight;
- Availability or cost of capital such as changes in: interest rates; market perceptions of the utility industry, PSCo, Xcel Energy Inc. or any of its other subsidiaries; or security ratings;
- Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by PSCo, Xcel Energy Inc. or any of its other subsidiaries;
- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementations of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in PSCo’s SEC filings, including “Risk Factors” in Item 1A of this Form 10-K, or in other publicly disseminated written documents.

PSCo undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.